

Integrated Resource Plan

Appendix 3A-1

2013 Resource Options Report Update

2013 Resource Options Report Update

Summary Table of Contents

Chapter 1. Overview

1.1 Introduction 1-1
 1.2 Structure of the 2013 ROR Update 1-1
 1.3 ROR Consultation 1-5
 1.4 Limitations of the 2013 ROR Update 1-6
 1.5 Comparison to the 2010 ROR..... 1-7

Chapter 2. Resource Options Results Summary

2.1 Introduction 2-1
 2.2 Demand-Side Management Options 2-1
 2.3 Supply-Side Generation Resource Options 2-1
 2.4 Supply-Side Transmission Resource Options..... 2-4

Chapter 3. Resource Options Attributes

3.1 Introduction 3-1
 3.2 Technical Attributes 3-1
 3.3 Financial Attributes 3-3
 3.4 Environmental Attributes 3-3
 3.5 Economic Development Attributes 3-6
 3.6 Data Confidence 3-8

Chapter 4. Demand-Side Management Options

4.1 Introduction 4-1
 4.1.1 Overview of DSM Options..... 4-1
 4.1.1.1 Energy and Capacity Options 4-2
 4.1.1.2 Capacity-Focused Options 4-3
 4.1.2 Attributes of DSM..... 4-4
 4.1.2.1 DSM Technical and Financial Attributes 4-4
 4.1.2.2 DSM Environmental and Economic
 Development Attributes 4-6
 4.2 Energy and Capacity DSM Options 4-6
 4.2.1 Option 1 4-11
 4.2.2 Option 2 4-12
 4.2.3 Option 3 4-16
 4.2.4 Options 4 and 5..... 4-17
 4.2.4.1 Option 4 Description 4-17
 4.2.5 Electricity Savings and Costs Comparison 4-21

| | | |
|---------|--|------|
| 4.3 | Capacity-Focused DSM Options..... | 4-26 |
| 4.3.1 | Industrial Load Curtailment..... | 4-26 |
| 4.3.1.1 | Description..... | 4-26 |
| 4.3.1.2 | Tactics..... | 4-27 |
| 4.3.2 | Capacity-Focused Programs..... | 4-27 |
| 4.3.2.1 | Description..... | 4-27 |
| 4.3.2.2 | Program Concepts..... | 4-27 |
| 4.3.3 | Capacity Savings and Costs Comparison..... | 4-28 |

Chapter 5. Supply-Side Resource Options

| | | |
|---------|--|------|
| 5.1 | Introduction..... | 5-1 |
| 5.1.1 | RODAT & ROMAP Databases..... | 5-1 |
| 5.1.2 | Resource Options Filters..... | 5-4 |
| 5.2 | Generation Resource Options..... | 5-8 |
| 5.2.1 | Wood Based Biomass – Standing Timber, Road Side and Sawmill Wood Waste..... | 5-8 |
| 5.2.1.1 | Resource Description..... | 5-8 |
| 5.2.1.2 | Methodology..... | 5-9 |
| 5.2.1.3 | Results..... | 5-11 |
| 5.2.1.4 | Environmental and Economic Development Attributes..... | 5-14 |
| 5.2.1.5 | Seasonality and Intermittence..... | 5-14 |
| 5.2.1.6 | Earliest In-Service Date..... | 5-15 |
| 5.2.1.7 | Uncertainty..... | 5-15 |
| 5.2.2 | Biomass – Biogas (Landfill)..... | 5-15 |
| 5.2.2.1 | Resource Description..... | 5-15 |
| 5.2.2.2 | Methodology..... | 5-17 |
| 5.2.2.3 | Technical and Financial Results..... | 5-19 |
| 5.2.2.4 | Environmental and Economic Development Attributes..... | 5-20 |
| 5.2.2.5 | Earliest In-Service Date..... | 5-20 |
| 5.2.2.6 | Seasonality and Intermittence..... | 5-20 |
| 5.2.2.7 | Uncertainty..... | 5-21 |
| 5.2.3 | Biomass – Municipal Solid Waste..... | 5-21 |
| 5.2.3.1 | Resource Description..... | 5-21 |
| 5.2.3.2 | Methodology..... | 5-23 |
| 5.2.3.3 | Technical and Financial Results..... | 5-26 |
| 5.2.3.4 | Environmental and Economic Development Attributes..... | 5-28 |

| | | | |
|-------|----------------------------|--|------|
| | 5.2.3.5 | Earliest In-Service Date | 5-28 |
| | 5.2.3.6 | Seasonality and Intermittence | 5-28 |
| | 5.2.3.7 | Uncertainty | 5-28 |
| 5.2.4 | Onshore Wind | | 5-28 |
| | 5.2.4.1 | Resource Description | 5-28 |
| | 5.2.4.2 | Methodology | 5-29 |
| | 5.2.4.3 | Technical and Financial Results | 5-31 |
| | 5.2.4.4 | Environmental and Economic Development Attributes | 5-32 |
| | 5.2.4.5 | Earliest In-Service Date | 5-32 |
| | 5.2.4.6 | Seasonality and Intermittence | 5-32 |
| | 5.2.4.7 | Uncertainty | 5-33 |
| 5.2.5 | Offshore Wind | | 5-33 |
| | 5.2.5.1 | Resource Description | 5-33 |
| | 5.2.5.2 | Methodology | 5-34 |
| | 5.2.5.3 | Technical and Financial Results | 5-35 |
| | 5.2.5.4 | Environmental and Economic Development Attributes | 5-36 |
| | 5.2.5.5 | Earliest In-Service Date | 5-36 |
| | 5.2.5.6 | Seasonality and Intermittence | 5-36 |
| | 5.2.5.7 | Uncertainty | 5-37 |
| 5.2.6 | Geothermal Potential | | 5-37 |
| | 5.2.6.1 | Resource Description | 5-38 |
| | 5.2.6.2 | Methodology | 5-41 |
| | 5.2.6.3 | Technical and Financial Results | 5-43 |
| | 5.2.6.4 | Environmental and Economic Development Attributes | 5-45 |
| | 5.2.6.5 | Earliest In-Service Date | 5-45 |
| | 5.2.6.6 | Seasonality and Intermittence | 5-46 |
| | 5.2.6.7 | Uncertainty | 5-46 |
| 5.2.7 | Run-of-River | | 5-47 |
| | 5.2.7.1 | Resource Description | 5-48 |
| | 5.2.7.2 | Methodology | 5-48 |
| | 5.2.7.3 | Technical and Financial Results | 5-52 |
| | 5.2.7.4 | Environmental and Economic Development Attributes | 5-54 |
| | 5.2.7.5 | Earliest In-Service Date | 5-54 |
| | 5.2.7.6 | Seasonality and Intermittence | 5-55 |
| | 5.2.7.7 | Uncertainty | 5-56 |

| | | |
|----------|---|------|
| 5.2.8 | Pumped Storage | 5-56 |
| 5.2.8.1 | Resource Description | 5-56 |
| 5.2.8.2 | Methodology | 5-57 |
| 5.2.8.3 | Technical and Financial Results | 5-57 |
| 5.2.8.4 | Environmental and Economic Development Attributes | 5-58 |
| 5.2.8.5 | Earliest In-Service Date | 5-59 |
| 5.2.8.6 | Seasonality and Intermittence | 5-59 |
| 5.2.8.7 | Uncertainty | 5-59 |
| 5.2.9 | Large Hydro - Site C | 5-59 |
| 5.2.9.1 | Resource Description | 5-59 |
| 5.2.9.2 | Methodology | 5-60 |
| 5.2.9.3 | Technical and Financial Attributes | 5-60 |
| 5.2.9.4 | Environmental and Economic Development Attributes | 5-61 |
| 5.2.9.5 | Earliest In-Service Date | 5-61 |
| 5.2.9.6 | Seasonality and Intermittence | 5-62 |
| 5.2.9.7 | Uncertainty | 5-62 |
| 5.2.10 | Resource Smart | 5-62 |
| 5.2.10.1 | Resource Description | 5-62 |
| 5.2.10.2 | Methodology | 5-64 |
| 5.2.10.3 | Technical and Financial Attributes | 5-64 |
| 5.2.10.4 | Environmental and Economic Development Attributes | 5-65 |
| 5.2.10.5 | Earliest In-Service Date | 5-65 |
| 5.2.10.6 | Seasonality and Intermittence | 5-65 |
| 5.2.10.7 | Uncertainty | 5-65 |
| 5.2.11 | Natural Gas-Fired Generation and Cogeneration | 5-65 |
| 5.2.11.1 | Resource Description | 5-66 |
| 5.2.11.2 | Methodology | 5-67 |
| 5.2.11.3 | Technical and Financial Results | 5-67 |
| 5.2.11.4 | Environmental and Economic Development Attributes | 5-69 |
| 5.2.11.5 | Earliest In-Service Date | 5-69 |
| 5.2.11.6 | Seasonality and Intermittence | 5-70 |
| 5.2.11.7 | Uncertainty | 5-70 |
| 5.2.12 | Coal-Fired Generation with Carbon Capture and Sequestration..... | 5-70 |
| 5.2.12.1 | Resource Description | 5-70 |

| | | | |
|--------|----------------------------|--|------|
| | 5.2.12.2 | Methodology | 5-71 |
| | 5.2.12.3 | Technical and Financial Results | 5-71 |
| | 5.2.12.4 | Environmental and Economic Development Attributes | 5-72 |
| | 5.2.12.5 | Earliest In Service Date | 5-72 |
| | 5.2.12.6 | Seasonality and Intermittence | 5-73 |
| | 5.2.12.7 | Uncertainty | 5-73 |
| 5.2.13 | Wave..... | | 5-73 |
| | 5.2.13.1 | Resource Description | 5-73 |
| | 5.2.13.2 | Methodology | 5-75 |
| | 5.2.13.3 | Technical and Financial Results | 5-76 |
| | 5.2.13.4 | Environmental and Economic Development Attributes | 5-77 |
| | 5.2.13.5 | Earliest In-Service Date | 5-77 |
| | 5.2.13.6 | Seasonality and Intermittence | 5-77 |
| | 5.2.13.7 | Uncertainty | 5-78 |
| 5.2.14 | Tidal..... | | 5-79 |
| | 5.2.14.1 | Resource Description | 5-79 |
| | 5.2.14.2 | Methodology | 5-80 |
| | 5.2.14.3 | Technical and Financial Results | 5-81 |
| | 5.2.14.4 | Environmental and Economic Development Attributes | 5-83 |
| | 5.2.14.5 | Earliest In-Service Date | 5-83 |
| | 5.2.14.6 | Seasonality and Intermittence | 5-83 |
| | 5.2.14.7 | Uncertainty | 5-84 |
| 5.2.15 | Hydrokinetic | | 5-84 |
| | 5.2.15.1 | Methodology | 5-85 |
| 5.2.16 | Storage Technologies | | 5-85 |
| | 5.2.16.1 | Resource Description | 5-85 |
| | 5.2.16.2 | Methodology | 5-88 |
| 5.2.17 | Solar | | 5-89 |
| | 5.2.17.1 | Resource Description | 5-89 |
| | 5.2.17.2 | Methodology | 5-91 |
| | 5.2.17.3 | Technical and Financial Results | 5-92 |
| | 5.2.17.4 | Environmental and Economic Development Attributes | 5-94 |
| | 5.2.17.5 | Earliest In-Service Date | 5-94 |
| | 5.2.17.6 | Seasonality and Intermittence | 5-94 |
| | 5.2.17.7 | Uncertainty | 5-95 |

| | | |
|----------|--|-------|
| 5.2.18 | Miscellaneous Distributed Generation | 5-96 |
| 5.2.18.1 | Resource Description | 5-96 |
| 5.2.18.2 | Methodology | 5-98 |
| 5.2.19 | Other Capacity Options..... | 5-98 |
| 5.2.20 | Nuclear | 5-98 |
| 5.2.21 | Generation Resource Potential Results Summary..... | 5-98 |
| 5.3 | Bulk Transmission Resource Options | 5-115 |
| 5.3.1 | Transmission Paths, Cut-Planes, and Congestion..... | 5-115 |
| 5.3.2 | Bulk Transmission Options | 5-117 |
| 5.3.3 | Transmission Expansion Projects..... | 5-120 |
| 5.3.4 | Regional Transmission Projects..... | 5-121 |
| 5.3.5 | Transmission for Export | 5-122 |
| 5.3.6 | Transmission for Interconnecting Individual New Resources... | 5-123 |
| 5.4 | Comparison to the 2010 ROR..... | 5-125 |

Chapter 6. Unit Energy Cost Adjustment

| | | |
|-----|---|-----|
| 6.1 | Introduction | 6-1 |
| 6.2 | Adjustments | 6-1 |
| 6.3 | Summary of Adjusted Firm Unit Energy Costs..... | 6-2 |

List of Figures

Chapter 2. Resource Options Results Summary

| | | |
|------------|---|-----|
| Figure 2-1 | Energy Resource Options Supply Curves (Adjusted Firm UEC \$/MWh)..... | 2-3 |
|------------|---|-----|

Chapter 4. Demand-Side Management Options

| | | |
|------------|-------------------------------------|------|
| Figure 4-1 | Energy Savings | 4-22 |
| Figure 4-2 | Associated Capacity Savings | 4-23 |
| Figure 4-3 | Total Resource Costs..... | 4-24 |
| Figure 4-4 | Utility Costs | 4-25 |
| Figure 4-5 | Combined Capacity Savings (MW)..... | 4-29 |

Chapter 5. Supply-Side Resource Options

| | | |
|------------|---|------|
| Figure 5-1 | Components (G, R, T) of the Resource Options Evaluated to the POI | 5-2 |
| Figure 5-2 | Ten Transmission Planning Regions..... | 5-4 |
| Figure 5-3 | Wood Based Biomass POI Supply Curves..... | 5-14 |
| Figure 5-4 | Biogas POI Supply Curves..... | 5-20 |

| | | |
|---|---|-------|
| Figure 5-5 | Biomass MSW POI Supply Curves | 5-27 |
| Figure 5-6 | Onshore Wind POI Supply Curves | 5-32 |
| Figure 5-7 | Normalized Monthly Onshore Wind Energy Profiles by Transmission Region..... | 5-33 |
| Figure 5-8 | Offshore Wind POI Supply Curves | 5-36 |
| Figure 5-9 | Normalized Monthly Offshore Wind Energy Profile | 5-37 |
| Figure 5-10 | Geothermal POI Supply Curves | 5-45 |
| Figure 5-11 | Run-of-river POI Supply Curves | 5-54 |
| Figure 5-12 | Normalized Monthly Run-of-river Energy Profiles by Transmission Region..... | 5-55 |
| Figure 5-13 | Pumped Storage POI Supply Curves | 5-58 |
| Figure 5-14 | CCGT and Small Cogeneration POI Supply Curves* | 5-69 |
| Figure 5-15 | Coal-Fired Generation with CCS POI Supply Curve* | 5-72 |
| Figure 5-16 | Wave POI Supply Curves..... | 5-77 |
| Figure 5-17 | Monthly Energy Profile – Wave Potential | 5-78 |
| Figure 5-18 | Tidal POI Supply Curve | 5-82 |
| Figure 5-19 | Monthly Energy Profile – Tidal Potential (Discovery Passage)..... | 5-83 |
| Figure 5-20 | Range of Application of existing Storage Technologies | 5-87 |
| Figure 5-21 | Solar POI Supply Curves | 5-94 |
| Figure 5-22 | Normalized Monthly Solar Energy Profiles by Transmission Region..... | 5-95 |
| Figure 5-23 | Supply-Side Generation Resource Potential Supply Curve Summary – Base UECs \$/MWh at POI | 5-100 |
| Figure 5-24 | Overview of Transmission System and Cut-Planes..... | 5-116 |
| Chapter 6. Unit Energy Cost Adjustment | | |
| Figure 6-1 | Resource Potential Supply Curve Summary – Adjusted Firm UEC Values (\$/MWh)..... | 6-4 |

List of Tables

| | | |
|--|---|-----|
| Chapter 2. Resource Options Results Summary | | |
| Table 2–1 | Summary of DSM Options..... | 2-1 |
| Table 2–2 | Summary of Supply-Side Energy Resource Options ¹ | 2-2 |
| Table 2–3 | Summary of Supply-Side Capacity Resource Options | 2-4 |
| Table 2–4 | Transmission Reinforcement Options Considered in Long-Term Resource Planning | 2-4 |

Chapter 3. Resource Options Attributes

Table 3-1 Generation Reliability Assumptions and Methods 3-2

Table 3-2 Environmental Attributes 3-4

Table 3-3 Economic Development Attributes 3-7

Table 3-4 Levels of Data Confidence for Resource Options 3-8

Chapter 4. Demand-Side Management Options

Table 4-1 Levels of Data Confidence for DSM Options 4-6

Table 4-2 Energy and Capacity DSM Options Comparison..... 4-8

Table 4-3 Option 2: Codes and Standards 4-14

Table 4-4 Option 2: Programs 4-15

Table 4-5 Option 2: Supporting Initiatives 4-16

Table 4-6 Option 5: Codes and Standards Changes 4-19

Table 4-7 Option 5: Conservation Rate Structure Changes 4-20

Table 4-8 Option 5: Program Changes 4-21

Table 4-9 TRC and UC for Energy and Capacity DSM Options 4-25

Table 4-10 Residential Program Concepts 4-27

Table 4-11 Commercial Program Concepts 4-28

Table 4-12 Industrial Program Concepts 4-28

Table 4-13 TRC and UC for Capacity-Focused DSM Options..... 4-29

Chapter 5. Supply-Side Resource Options

Table 5-1 Exclusion Zones 5-5

Table 5-2 Summary of Wood Based Biomass Potential 5-13

Table 5-3 Summary of Biogas Potential 5-19

Table 5-4 Summary of MSW Potential 5-27

Table 5-5 Summary of Onshore Wind Potential 5-31

Table 5-6 Summary of Offshore Wind Potential 5-35

Table 5-7 Summary of Geothermal Potential 5-44

Table 5-8 Summary of Run-of-river Potential 5-53

Table 5-9 Summary of Pumped Storage Potential 5-57

Table 5-10 Site C Summary 5-61

Table 5-11 Summary of Resource Smart Potential 5-64

Table 5-12 Summary of CCGT and Small Cogeneration Natural Gas
 Fired Generation Potential 5-67

Table 5-13 Summary of the SCGT Natural Gas-Fired Generation
 Potential 5-68

Table 5-14 Summary of Coal-Fired Generation with CCS Potential 5-71

Table 5-15 Summary of Wave Potential 5-76

| | | |
|---|---|-------|
| Table 5-16 | Summary of Tidal Potential | 5-82 |
| Table 5-17 | Summary of Storage Technologies and Applications | 5-88 |
| Table 5-18 | Summary of Solar Potential..... | 5-93 |
| Table 5-19 | Inventory of Supply-Side Generation Resource Potential by Transmission Region..... | 5-99 |
| Table 5-20 | Supply-Side Generation Resource Potential – UEC Values at POI below \$200/MWh | 5-101 |
| Table 5-21 | Summary of Supply-Side Energy Resource Potential by Resource Type – UEC Values at POI | 5-113 |
| Table 5-22 | Summary of Supply-Side Capacity Resource Potential – UCC at POI Summary..... | 5-114 |
| Table 5-23 | Cut-Plane Capacities..... | 5-117 |
| Table 5-24 | Transmission Reinforcement Options Considered in Long-Term Resource Planning | 5-118 |
| Table 5-25 | Unit Cost of Power Lines..... | 5-124 |
| Table 5-26 | Interconnection Substation Cost | 5-124 |
| Table 5-27 | Voltage Transformation Cost..... | 5-124 |
| Chapter 6. Unit Energy Cost Adjustment | | |
| Table 6-1 | Summary of Supply-Side Energy Resource Options Potential – UEC at POI and Adjusted Firm UEC Values | 6-3 |

List of Appendices

| | |
|---------------|---|
| Appendix 1 | Resource Options Update Consultation Report |
| Appendix 2 | Environmental Attributes Review and Update |
| Appendix 3 | Resource Options Database (RODAT) Summary Sheets |
| Appendix 4 | Economic Development Attributes |
| Appendix 5-A | Resource Options Mapping (ROMAP) Report |
| Appendix 5-A1 | Resource Options Mapping (ROMAP) Report Report Attachment: Figure 2-1 – Potential Biomass: Biogas |
| Appendix 5-A2 | Report Attachment: Figure 2-2 – Potential Biomass: Municipal Solid Waste |
| Appendix 5-A3 | Report Attachment: Figure 2-3 – Potential Biomass: Wood Based |
| Appendix 5-A4 | Report Attachment: Figure 2-4 – Potential Geothermal |
| Appendix 5-A5 | Report Attachment: Figure 2-5 – Potential Large Hydro: Site C |
| Appendix 5-A6 | Report Attachment: Figure 2-6 – Potential Pumped Storage (Lower Mainland, Vancouver Island and Mica) |

| | |
|----------------|--|
| Appendix 5-A7 | Report Attachment: Figure 2-7 – Potential Resource Smart |
| Appendix 5-A8 | Report Attachment: Figure 2-8 – Potential Run-of-River |
| Appendix 5-A9 | Report Attachment: Figure 2-9 – Potential Solar |
| Appendix 5-A10 | Report Attachment: Figure 2-10 – Potential Natural Gas-Fired Generation & Cogeneration |
| Appendix 5-A11 | Report Attachment: Figure 2-11 – Potential Coal-Fired Generation with Carbon Capture & Sequestration |
| Appendix 5-A12 | Report Attachment: Figure 2-12 – Potential Tidal |
| Appendix 5-A13 | Report Attachment: Figure 2-13 – Potential Wave |
| Appendix 5-A14 | Report Attachment: Figure 2-14 – Potential Wind: Onshore & Offshore |
| Appendix 5-A15 | Report Attachment: Figure 2-15 - Transmission Regions |
| Appendix 5-A16 | Report Attachment: Figure 2-16 - Energy Density |
| Appendix 5-A17 | Report Attachment: Figure 2-17 - Capacity Density |
| Appendix 5-A18 | Report Appendices: A and B |
| Appendix 6 | Wood Based Biomass Potential Report |
| Appendix 7 | Wind Cost Review Report |
| Appendix 8-A | Run of River Report - 2013 Update Memorandum and 2010 Report |
| Appendix 8-A1 | Report Attachment: Map E-1 |
| Appendix 8-A2 | Report Appendices: A to C |
| Appendix 9-A | Lower Mainland / Vancouver Island Pumped Storage Report and North Coast Pumped Storage Report |
| Appendix 9-B | Mica Pumped Storage Report |
| Appendix 10 | Coal-Fired Generation with Carbon Capture and Sequestration |
| Appendix 11 | Ocean Renewable Energy Group Submission |
| Appendix 12 | Firm Energy Cost Adjustments |
| Appendix 13 | Glossary of Acronyms |

2013 Resource Options Report Update

Chapter 1

Overview

Table of Contents

| | | |
|-----|--|-----|
| 1.1 | Introduction | 1-1 |
| 1.2 | Structure of the 2013 ROR Update | 1-1 |
| 1.3 | ROR Consultation | 1-5 |
| 1.4 | Limitations of the 2013 ROR Update | 1-6 |
| 1.5 | Comparison to the 2010 ROR..... | 1-7 |

1.1 Introduction

The 2013 Resource Options Report (**ROR**) Update presents an assessment of the potential resource options available to meet the needs of BC Hydro's electricity customers over the next 20 to 30 years.¹ The information presented in this report reflects a targeted update to the 2010 ROR which include three of the five demand-side management (**DSM**) options, wood-based biomass, municipal solid waste (**MSW**), onshore/offshore wind, run-of-river, Resource Smart and natural gas-fired generation. Refer to section [1.5](#) for more details.

The 2013 ROR Update considers demand-side and supply-side resource options that are consistent with the policy and legislated objectives of the B.C. Government, including those specified in its 2010 *Clean Energy Act* (**CEA**). All identified options are inventoried in the Resource Options Database (**RODAT**), which is a Microsoft Access database, and the Resource Options Mapping Database (**ROMAP**), which is a spatially enabled Geographical Information System (**GIS**) version of RODAT.

Both databases contain key details about potential resource options such as the project description, as well as technical, financial, environmental and economic development information. They are used as input into the Integrated Resource Plan (**IRP**) portfolio analysis where the costs and impacts of new resource additions to meet the energy and capacity needs of BC Hydro's domestic customers are assessed on a system-wide basis over the planning period, including DSM, generation and transmission resources.

1.2 Structure of the 2013 ROR Update

The 2013 ROR Update consists of six chapters and 13 appendices.

Chapter 1 provides an overview of the ROR components, including brief descriptions of the appendices.

¹ BC Hydro's long-term planning period extends 20 years for DSM and generation resources and 30 years for transmission options.

1 **Chapter 2** presents a summary of the 2013 ROR Update including DSM options,
2 energy resource options, capacity resource options and transmission options.

3 **Chapter 3** describes the high level attributes used in the resource options
4 comparison and evaluation process, e.g., technical, financial, environmental and
5 economic development attributes and data confidence.

6 **Chapter 4** presents two sets of DSM options, which include five energy and capacity
7 options and two capacity-focused options with their varying levels of confidence.

8 **Chapter 5** presents an overview of the supply-side resource options including
9 generation, storage and transmission resources with their underlying assumptions.

10 **Chapter 6** describes the cost adjustment process to facilitate a high level
11 comparison of costs across resource types and to reflect the cost of resources
12 delivered to the Lower Mainland load center.

13 **Appendix 1 - Resource Options Update Consultation Report** describes the
14 objectives of the consultation process, the process used, the input BC Hydro
15 received, and how BC Hydro considered the input.

16 **Appendix 2 - Environmental Attributes Review and Update** presents a
17 description of the selected attributes and the criteria used for their selection and a
18 discussion of the resource options and their land and water footprints.

19 **Appendix 3 - Resource Options Database (RODAT) Summary Sheets** present
20 details of the resource options that are further considered in the portfolio analysis.

21 **Appendix 4 - Economic Development Attributes** describes the methodology, data
22 and assumptions used by BC Hydro to develop economic development attributes for
23 long-term resource planning.

24 **Appendix 5 - Resource Options Mapping (ROMAP)** contains the following
25 documents:

- 1 • **Appendix 5-A** is the ROMAP Report that presents over 7,700 potential
2 resource options in B.C. in a spatially enabled GIS version. It includes
3 17 attachments that were too large to include with the ROMAP Report as one
4 file (these are labelled as ROR Appendices 5-A1 to 5-A17). There are also two
5 appendices to the ROMAP Report that are provided as one file (this is labelled
6 as ROR Appendix 5-A18).
- 7 • **Appendices 5-A1 to 5-A14** present the mapped generation resource options
8 by resource type
- 9 • **Appendix 5-A15** shows the existing transmission system and region
10 delineation
- 11 • **Appendices 5-A16 and 5-A17** show the energy and capacity density of B.C.
12 potential resource options respectively
- 13 • **Appendix 5-A18** contains two appendices to the ROMAP report:
 - 14 ▶ Appendix A - Density Analysis Using GIS
 - 15 ▶ Appendix B - Roads & Power Lines Cost Estimation Using GIS

16 **Appendix 6 - Wood Based Biomass Potential Report** provides an update to the
17 2010 modeling study conducted by a team of consultants including Industrial Forest
18 Services Ltd., M.D.T. Ltd., and Murray Hall Consulting Ltd. to forecast the potential
19 availability of wood based biomass fuels, with associated cost, that may be used for
20 electricity generation over the planning period.

21 **Appendix 7 - Wind Cost Review Report** provides Garrad Hassan Canada Inc.'s
22 capital and operational and maintenance (**O&M**) cost data reflective of 2010/2011
23 market conditions for the onshore and offshore wind.

24 **Appendix 8 - Run-of-River** contains the following documents:

- 25 • **Appendix 8-A** is the Run-of-River Report that provides an update to Kerr Wood
26 Leidal's (**KWL**) March 2011 Run-of-River potential study.

- 1 • **Appendix 8-A1** shows the location of nearly 7,300 run-of-river potential sites
2 with associated size and estimated unit energy cost range.
- 3 • **Appendix 8-A2** contains three appendices to the Run-of-River report:
 - 4 ▶ Appendix A: Hydrologic Gauge Data
 - 5 ▶ Appendix B: Roads & Power Lines Cost Estimation Using GIS
 - 6 ▶ Appendix C: Hydropower Potential by Transmission Region

7 **Appendix 9 - Pumped Storage** contains the following two documents:

- 8 • **Appendix 9-A** consists of two Pumped Storage Reports prepared by Knight
9 Piésold, which present a screening assessment of the pumped storage
10 potential in the Lower Mainland and Vancouver Island region, and the North
11 Coast region of B.C.
- 12 • **Appendix 9-B** is the Mica Pumped Storage Report prepared by Hatch Ltd.,
13 which provides a preliminary study and cost estimate for addition of pumped
14 storage at Mica Dam.

15 **Appendix 10 - Coal-Fired Generation with Carbon Capture and Sequestration**
16 presents Powertech Labs Inc.'s assessments on the coal and carbon dioxide (CO₂)
17 sequestration (CCS) locations in B.C., the potential of coal-fired power generation
18 with integrated gasification combined cycle (IGCC)-CCS in B.C., an update on the
19 clean coal technology status, and the cost of coal-fired generation with CCS.

20 **Appendix 11 - Ocean Renewable Energy Group (OREG) Submission** provides
21 OREG's view on the exploration of the B.C. ocean energy resources opportunities.

22 **Appendix 12 - Firm Energy Cost Adjustments** provides more details on the cost
23 adjustment process and how the cost adjusters were developed and applied.

24 **Appendix 13 - Glossary of Acronyms** provides the list of acronyms used in the
25 ROR.

1 **1.3 ROR Consultation**

2 The 2010 ROR consultation process is described below. BC Hydro did not consult
3 specifically on the 2013 ROR Update prior to its release in the IRP.

4 The 2010 ROR consultation process consisted of working with people who have
5 technical expertise to gather and review technical information on supply-side and
6 demand-side² resource options in B.C. The objectives of the 2010 ROR consultation
7 process were:

- 8 • Promote mutual understanding of the resource options data and continue to
9 foster constructive working relationships
- 10 • Seek input on methodology applied to updating the resource options data and
11 attributes where appropriate
- 12 • Seek input to accurately reflect resource options potential in the B.C. provincial
13 context

14 The review of the generation resource options was initiated in May 2010 and was
15 followed by technical review sessions with targeted stakeholders on the technical,
16 financial, environmental and economic development attributes of the options and
17 associated assumptions.

18 Engagement on the update of individual resource options was launched through a
19 workshop held on September 14, 2010, that among other topics, addressed the
20 scope and timing of the 2010 ROR. During the workshop, resource-specific
21 break-out sessions were held to introduce the proposed scope of assessment for
22 specific resources. Participants attending these sessions had the opportunity to sign
23 up and further participate in the resource-specific update process. Following this
24 workshop, resource-specific engagement sessions were scheduled by the BC Hydro

² BC Hydro worked with its Electricity Conservation and Efficiency (**EC&E**) Advisory Committee as it constructed plan options for DSM.

1 resource options task leads to review technical studies with interested participants
2 and contracted consultants.

3 As part of the environmental attributes update, targeted meetings occurred to review
4 the proposed attributes with government staff in August 2010, as well as
5 representatives of environmental organizations in September 2010.

6 A report-out session was held on December 8, 2010, during which participants were
7 presented preliminary results and the draft 2010 ROR. A written comment period,
8 from December 8 to December 31, 2010, provided additional opportunities for
9 interested parties to review the draft 2010 ROR and submit comments, which were
10 considered in finalizing the 2010 ROR.

11 A detailed 2010 ROR consultation report is included in Appendix 1 of the
12 2013 ROR Update.

13 **1.4 Limitations of the 2013 ROR Update**

14 The 2013 ROR Update provides an assessment of the potential resource options at
15 a level of detail and accuracy that is appropriate for long-term resource planning and
16 portfolio analysis.

17 It should be noted that the 2013 ROR Update planning level information, associated
18 with the generation and transmission resource options, is not considered sufficiently
19 accurate to establish the characteristics of site-specific resource options for
20 development or acquisition purposes. Specific on-site studies would be required to
21 determine the technical feasibility and cost-effectiveness of potential projects.

22 In the 2013 ROR Update, all resource options are presented as options for
23 consideration and do not commit BC Hydro to the implementation of any particular
24 options.

1 **1.5 Comparison to the 2010 ROR**

2 The 2010 ROR was developed based on information from BC Hydro’s project
3 experience, consultant studies, and First Nations and stakeholder input, including
4 input from people with relevant technical expertise and information such as
5 independent power producers (**IPPs**). In addition, technical studies were conducted
6 by BC Hydro and its consultants on a number of options, including coal-fired
7 generation with CCS, run-of-river hydroelectric, wood-based biomass and pumped
8 storage. These studies are referenced under each individual resource option.

9 For the 2013 ROR Update, information obtained in the 2010 ROR was reviewed for
10 material changes to availabilities or costs. BC Hydro resources and those resource
11 options bid into previous acquisitions processes by IPPs have been reviewed and
12 updated. These updates include three of the five DSM options, some Resource
13 Smart projects such as the GM Shrum generating station (**GMS**) Units 1-5 Capacity
14 Increase, and updates to available resource options including wood-based biomass,
15 MSW, onshore/offshore wind, run-of-river and natural gas-fired generation. There
16 have also been updates to other resources such as geothermal, pumped storage
17 and solar resource options.

18 The Unit Energy Costs (**UECs**) and Unit Capacity Costs (**UCCs**) have been updated
19 for all resource options using BC Hydro’s updated Weighted Average Cost of Capital
20 (**WACC**) to reflect long-term forecasts of project borrowing costs and the lower
21 financing costs available in the markets. BC Hydro-owned projects utilized a
22 5 per cent real cost of capital. Third party developed projects utilized a 7 per cent
23 real cost of capital. All results are presented in constant dollars as of
24 January 1, 2013 (\$2013).

2013 Resource Options Report Update

Chapter 2

Resource Options Results Summary

Table of Contents

| | | |
|-----|--|-----|
| 2.1 | Introduction | 2-1 |
| 2.2 | Demand-Side Management Options | 2-1 |
| 2.3 | Supply-Side Generation Resource Options | 2-1 |
| 2.4 | Supply-Side Transmission Resource Options..... | 2-4 |

List of Figures

| | | |
|------------|---|-----|
| Figure 2–1 | Energy Resource Options Supply Curves (Adjusted Firm UEC \$/MWh)..... | 2-3 |
|------------|---|-----|

List of Tables

| | | |
|-----------|--|-----|
| Table 2–1 | Summary of DSM Options | 2-1 |
| Table 2–2 | Summary of Supply-Side Energy Resource Options ¹ | 2-2 |
| Table 2–3 | Summary of Supply-Side Capacity Resource Options..... | 2-4 |
| Table 2–4 | Transmission Reinforcement Options Considered in Long-Term Resource Planning | 2-4 |

1 **2.1 Introduction**

2 The following chapter presents a summary of the resource options results.

3 **2.2 Demand-Side Management Options**

4 As summarized in [Table 2-1](#), two sets of demand-side management (DSM) options
5 were developed: energy and capacity options and capacity-focused options.

6 **Table 2-1 Summary of DSM Options**

| DSM Energy and Capacity Options | Total Resource Cost (\$/MWh) | Utility Cost (\$/MWh) |
|---|---|----------------------------------|
| Option 1: A scaling back of the current DSM activities to generally meet 66 per cent of the load growth. | 32 | 18 |
| Option 2: An update of BC Hydro's current DSM plan with a balanced offering of codes and standards, conservation rate structures, and programs. | 32 | 18 |
| Option 3: Expands programs to the limit of cost-effectiveness. Keeps codes and standards and conservation rate structures the same as in Option 2. | 35 | 22 |
| Option 4: Builds upon Option 3 and expands the codes and standards and conservation rate structure tools. | 47 | 30 |
| Option 5: Reflects an aggressive effort to change market parameters and societal norms and patterns in order to save electricity. | 49 | 29 |
| DSM Capacity-Focused Options | Total Resource Cost (\$/kW-year) | Utility Cost (\$/kW-year) |
| Industrial Load Curtailment: Targets large customers who agree to curtail load on short notice to provide capacity relief during peak periods. | 31 | 45 |
| Capacity-Focused Programs: Utilize equipment and load management systems for peak load reductions. | 55 | 69 |

7 **2.3 Supply-Side Generation Resource Options**

8 For the 2013 Resource Options Report (ROR) Update, the unit energy cost (UEC) of
9 the potential supply-side resource options at point of interconnection (POI) were

1 determined and then adjusted to reflect the cost of resources delivered to the Lower
 2 Mainland. The results are summarized in [Table 2-2](#) and [Figure 2-1](#) as follows:

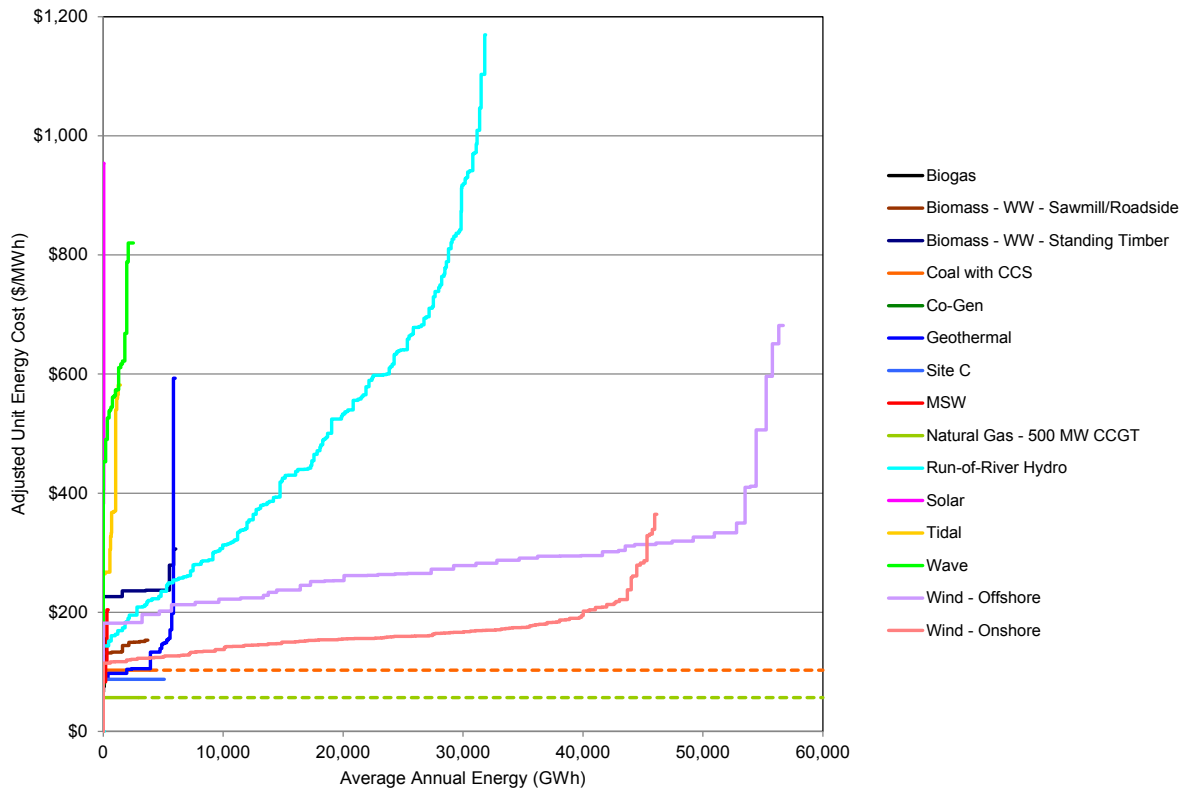
3 **Table 2-2 Summary of Supply-Side Energy**
 4 **Resource Options¹**

| Energy Resource | Total FELCC Energy (GWh/year) | Total DGC or ELCC Capacity (MW) | UEC at POI @ 7% Real (\$2013/MWh) | Adjusted Firm UEC ² @ 7% Real (\$2013/MWh) |
|---|-------------------------------|---------------------------------|-----------------------------------|---|
| Biomass – Wood Based | 9,772 | 1,226 | 122 – 276 | 132 – 306 |
| Biomass – Biogas | 134 | 16 | 59 – 154 | 56 – 156 |
| Biomass – Municipal Solid Waste | 425 | 50 | 85 – 184 | 83 – 204 |
| Wind – Onshore | 46,165 | 4,271 | 90 – 309 | 115 – 365 |
| Wind – Offshore | 56,700 | 3,819 | 166 – 605 | 182 – 681 |
| Geothermal | 5,992 | 780 | 91 – 573 | 90 – 593 |
| Run-of-River | 24,543 | 1,149 | 97 – 493 | 143 – 1,170 |
| Site C ³ | 4,700 | 1,100 | 83 | 88 |
| Combined Cycle Gas Turbine and Cogeneration ⁴ | 6,103 | 774 | 58 – 92 | 57 – 86 |
| Coal-fired Generation with Carbon Capture and Sequestration | 3,896 | 556 | 88 | 103 |
| Wave | 2,506 | 259 | 440 – 772 | 453 – 820 |
| Tidal | 1,426 | 247 | 253 – 556 | 264 – 581 |
| Solar | 57 | 12 | 266 – 746 | 341 – 954 |

- 5 Notes:
- 6 1. The resources and UEC values shown for each category in the table reflect the resource potential analyzed
 7 and may not include all possible resources that may be available at an expected higher cost.
- 8 2. The details of how the cost adjusters were developed and applied are provided in Appendix 12.
- 9 3. The Site C values presented in this table are based on information provided in the Site C Environmental
 10 Impact Statement (**EIS**) submission filed in January 2013, and the UEC is calculated assuming 5 per cent
 11 real discount rate.
- 12 4. Representative projects were used to characterize the natural gas-fired and coal-fired resource options, and
 13 the resource potential is generally considered to be unlimited.

1
2

Figure 2-1 Energy Resource Options Supply Curves (Adjusted Firm UEC \$/MWh)



3 Notes:

- 4 1. The resources and UEC values shown for each category in the table reflect the resource potential analyzed
- 5 and may not include all possible resources that may be available at an expected higher cost.
- 6 2. The Site C values presented in this table are based on information provided in the Site C EIS submission filed
- 7 in January 2013.
- 8 3. Representative projects were used to characterize the natural gas-fired and coal-fired resource options.
- 9 Dotted lines indicate additional potential, which is generally considered to be unlimited.

10 The unit capacity costs (**UCCs**) of the supply-side capacity resource options are

11 summarized in [Table 2-3](#) as follows.

Table 2-3 Summary of Supply-Side Capacity Resource Options

| Resource Type | Capacity Options | Dependable Capacity (MW) | UCC at POI @ 7% Real (\$2013/kW-year) |
|--------------------------------|---------------------------------|--------------------------|---------------------------------------|
| Resource Smart | GMS Units 1-5 Capacity Increase | 220 | 35 * |
| Resource Smart | Revelstoke Unit 6 | 488 | 50 * |
| Natural Gas – fired Generation | SCGTs at various locations | 98 or 101 | 84 or 180 |
| Pumped Storage | PS at Mica Generating Station | 465 | 100* |
| Pumped Storage | PS at various Locations | 1,000 | 118 – 124 |

Notes:

1. GMS Units 1-5 Capacity Increase numbers are based on conceptual level estimates.
2. Simple Cycle Gas Turbine (SCGT) and Pumped Storage (PS) only include fixed costs.
3. UCCs for GMS Units 1-5 Capacity Increase, Revelstoke Unit 6, and PS at Mica Generating Station are calculated assuming 5 per cent real discount rate.
4. Two SCGT representative projects are used to characterize the Natural Gas resource option.
5. Presentation of PS data is limited to results below \$125/kW-year.

2.4 Supply-Side Transmission Resource Options

The bulk transmission resource options considered in the 2013 ROR Update are presented in [Table 2-4](#).

Table 2-4 Transmission Reinforcement Options Considered in Long-Term Resource Planning

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$ Million) | Incremental Capacity (MW) | Line Length (km) |
|-----------------------|---|-------------------|-------------------------------|---------------------------|------------------|
| North Interior | | | | | |
| TO-01 | New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston | 8 | 388.3 | 1470 | 278 |
| TO-02 | New 500 kV, 50 per cent series compensated transmission circuit 5L14 between Williston and Kelly Lake | 8 | 341.1 | 2120 | 330 |

Integrated Resource Plan Appendix 3A-1

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$ Million) | Incremental Capacity (MW) | Line Length (km) |
|--------------------|---|-------------------|-------------------------------|----------------------------------|------------------|
| TO-03 | New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1 | 8 | 1,482.9 | 1000 | 928 |
| TO-04 | New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2 | 8 | 246.8 | 1000 | N/A |
| TO-05 | Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating. | 3 | 59.5 | 360 (CI-KLY/NIC) and 300 (PR-CI) | N/A |
| TO-06 | Series compensation upgrade at McLeese from 50 per cent to 65 per cent on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating. | 3 | 57.2 | 390 (CI-KLY/NIC) and 330 (PR-CI) | N/A |
| TO-07 | 500 kV Shunt compensation: <ul style="list-style-type: none"> • At Williston add one 300 MVAR SVC and two 250 MVAR switchable capacitor banks. • At Kelly Lake add one 250 MVAR shunt capacitor | 3 | 65.1 | 650 (CI-KLY/NIC) and 580 (PR-CI) | N/A |
| North Coast | | | | | |
| TO-08 | New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing 5L61 - 5L62 and 5L63 lines. | 8 | 1,031.6 | 970 | 449 |
| TO-09 | Series compensation of the WSN-SKA 500 kV lines 5L61, 5L62 and 5L63 plus voltage support and transformation addition in the existing BC Hydro substations | 3 | 142.3 | 580 | N/A |
| TO-21 | A new +/-500 kV HVDC bipole transmission circuit between WSN and SKA | 8 | 1,091.6 | 2000 | 449 |

Integrated Resource Plan Appendix 3A-1

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$ Million) | Incremental Capacity (MW) | Line Length (km) |
|-----------------------------------|---|--------------------------|--------------------------------------|---|-------------------------|
| South Interior | | | | | |
| TO-10 | New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake | 8 | 226.7 | 750 | 163 |
| TO-11 | New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola | 8 | 196.3 | 750 | 138 |
| TO-12 | 50 per cent series compensation of the 500 kV lines 5L91 and 5L98 | 3 | 61.8 | 133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK) | N/A |
| TO-13 | 50 per cent series compensation of 500 kV lines 5L71 and 5L72 | Committed in 2014 | 46.0 | 950 | N/A |
| TO-14 | 50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96 | 3 | 60.3 | 112 | N/A |
| TO-19 | 50 per cent Series compensation of 500 kV line 5L92 SEL-CBK. | 3 | 31.2 | 150 | N/A |
| TO-20 | A new 500 kV line between Selkirk and Cranbrook parallel to the existing 500 kV line 5L92 | 8 | 651.1 | 1550 | 180 |
| Interior to Lower Mainland | | | | | |
| TO-15 | New 500 kV, 50 per cent series compensated transmission circuit 5L83 between Nicola and Meridian | Committed in 2015 | 609.2 | 1550 | 247 |
| TO-16 | New 500 kV, 50 per cent series compensated transmission circuit 5L46 between Kelly Lake and Cheekye | 8 | 656.7 | 1384 | 197 |

Integrated Resource Plan Appendix 3A-1

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$ Million) | Incremental Capacity (MW) | Line Length (km) |
|-----------------|---|--------------------------|--------------------------------------|----------------------------------|-------------------------|
| TO-17 | 500 kV and 230 kV shunt compensation: <ul style="list-style-type: none"> • At Meridian 230 kV add two 110 MVAR capacitor banks • At Nicola 500 kV add one 250 MVAR capacitor bank | 3 | 10.1 | 570 | N/A |
| | Lower Mainland to Vancouver Island | | | | |
| TO-18 | New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal | 6 | 230.1 | 600 | 67 |

1 Note: TO-15 presented in this table is based on information filed with BCUC in November 2011.

2013 Resource Options Report Update

Chapter 3

Resource Options Attributes

Table of Contents

| | | |
|-----|---------------------------------------|-----|
| 3.1 | Introduction | 3-1 |
| 3.2 | Technical Attributes | 3-1 |
| 3.3 | Financial Attributes | 3-3 |
| 3.4 | Environmental Attributes | 3-3 |
| 3.5 | Economic Development Attributes | 3-6 |
| 3.6 | Data Confidence | 3-8 |

List of Tables

| | | |
|-----------|--|-----|
| Table 3-1 | Generation Reliability Assumptions and Methods..... | 3-2 |
| Table 3-2 | Environmental Attributes..... | 3-4 |
| Table 3-3 | Economic Development Attributes | 3-7 |
| Table 3-4 | Levels of Data Confidence for Resource Options | 3-8 |

1 **3.1 Introduction**

2 To compare and evaluate the resource options, technical, financial, environmental
3 and economic development attributes of the resource options were developed as
4 described in the following sections.

5 **3.2 Technical Attributes**

6 The technical attributes considered for each resource option are:

- 7 • Installed Capacity (MW)
- 8 • Dependable Generating Capacity (**DGC**) for non-intermittent resources (MW),
9 and Effective Load Carrying Capability (**ELCC**) for intermittent (or variable)
10 generation resources (MW)
- 11 • Average Annual Energy (GWh/year)
- 12 • Firm Energy Load Carrying Capability (**FELCC**) (GWh/year)
- 13 • Monthly per cent of Average Annual Energy

14 A summary of the generation reliability criteria, assumptions and methods of
15 development is contained in [Table 3-1](#).

1
2

Table 3-1 Generation Reliability Assumptions and Methods

| Potential Generation Resources | DGC¹ and ELCC² Assumptions and Methods of Determination | FELCC³ Assumptions and Methods of Determination |
|---|---|--|
| Run-of-river | ELCC: Weighted average of approximately 60 per cent of the forecasted average MW of potential in the December/January period | Region specific factors applied to the average annual energy |
| Biomass | DGC: 100 per cent of installed capacity for wood-based biomass; 97 per cent of installed capacity for municipal solid waste; and 95 per cent of installed capacity for biogas | 100 per cent of average annual energy |
| Wind – Onshore | ELCC: 26 per cent of installed capacity | 100 per cent of average annual energy |
| Wind – Offshore | ELCC: 26 per cent of installed capacity | 100 per cent of average annual energy |
| Geothermal | DGC: 100 per cent of installed capacity | 100 per cent of average annual energy |
| Natural Gas-fired Generation and Cogeneration | DGC: Varies from 88 per cent to 100 per cent of installed capacity | Based on 18 per cent capacity factor for SCGT; and 90 per cent for Combined Cycle Gas Turbine (CCGT) |
| Site C ⁴ | DGC: 1,100 MW | 4,700 GWh/year |
| Pumped Storage | DGC: 100 per cent of installed capacity | N/A |
| Wave | ELCC: Assumed 24 per cent of installed capacity | Assumed the same as offshore wind at 100 per cent of average annual energy |
| Tidal | ELCC: 40 per cent of installed capacity | 100 per cent of average annual energy |
| Solar | ELCC: Assumed 24 per cent of installed capacity | Assumed the same as onshore wind at 100 per cent of average annual energy |
| Resource Smart (GMS Units 1-5 Capacity Increase) | DGC: 220 MW | To be determined but likely to be small |
| Resource Smart (Revelstoke Unit 6) | DGC: 488 MW | 26 GWh/year |
| Coal-fired Generation with Carbon Capture and Sequestration | DGC: 75 per cent of installed capacity | 100 per cent of average annual energy |

3 Note:

4 1. DGC is the amount of megawatts a plant can reliably produce when required, assuming all units are in
5 service.

- 1 2. ELCC is the maximum peak load that a generating unit or system of units can reliably supply such that the
2 loss of load expectation will be no greater than one day in 10 years.
- 3 3. FELCC is the maximum amount of annual energy that a hydroelectric system can produce under critical
4 water conditions.
- 5 4. Site C value is based on information provided in the Site C Environmental Impact Statement (EIS)
6 submission filed in January 2013 with the Canadian Environmental Agency and the B.C. Environmental
7 Assessment Office.

8 **3.3 Financial Attributes**

9 The following financial attributes and assumptions were used in developing the
10 2013 Resource Options Report (ROR) Update:

- 11 • **Weighted Average Cost of Capital:** 5 per cent and 7 per cent real cost of
12 capital rates are used in determining unit energy costs (UEC) of BC Hydro
13 resources and IPP resources, respectively. In comparison to the
14 2010 Resource Options assessment, lower costs of capital are implemented to
15 reflect a reduction in project borrowing costs. These rates do not presume or
16 prescribe a specific capital structure.
- 17 • **UEC & Unit Capacity Cost (UCC) Methodology:** The UEC and UCC
18 measures reflect the levelized cost of a unit of energy or capacity of a resource
19 option. The methodology used to calculate these values is unchanged from the
20 2006 Integrated Electricity Plan (IEP) and the 2008 Long-Term Acquisition Plan
21 (LTAP) resource options updates.
- 22 • The resource options costs are shown as UECs and UCCs at point of
23 interconnection (POI) in constant dollars on January 1, 2013 (\$2013).

24 **3.4 Environmental Attributes**

25 The same environmental attributes developed for the 2010 ROR are used to
26 characterize the resource options. These attributes were selected based upon the
27 following criteria:

- 28 • Appropriate for provincial-scale portfolio comparisons
- 29 • Science-based and defensible

- 1 • Measurable in a “quantity”-based approach that facilitate comparison between
- 2 portfolios of resource options
- 3 • Representative of relevant biophysical resources
- 4 • Based on existing data or easily acquired data
- 5 • Easy to understand for long-range planning and stakeholder engagement
- 6 purposes

7 A consultant team consisting of Kerr Wood-Leidal, HEMMERA, and HB Lanarc was
 8 retained by BC Hydro to develop the environmental attributes. A detailed description
 9 of the environmental attributes, associated methodology and rationale can be found
 10 in Appendix 2.

11 The environmental attributes are grouped into four environmental categories: land,
 12 atmosphere, freshwater and marine (a new category selected to accommodate
 13 emerging energy potential, such as offshore wind, tidal and wave resource options)
 14 and are further broken down into indicators as described in [Table 3-2](#).

Table 3-2 Environmental Attributes

| Environmental Category | Indicator | Unit of Measure | Classifications |
|------------------------|---|-------------------------|------------------------|
| Land | Net Primary Productivity (NPP) (gC/m ² /year) | hectares (ha) per class | Low (0 to < 69) |
| | | | Medium (69 to < 369) |
| | | | High (> 369) |
| | Remoteness – Linear Disturbance Density (km/km ²) | ha per class | Wilderness (< 0.2) |
| | | | Remote (0.2 to < 0.66) |
| | | | Rural (0.66 to 2.2) |
| | | | Urban (> 2.2) |
| | High Priority Species Count (percentile) | ha per class | 0 to < 20 |
| | | | 20 to < 40 |
| | | | 40 to < 60 |
| | | | 60 to 80 |
| > 80 | | | |

Integrated Resource Plan Appendix 3A-1

| Environmental Category | Indicator | Unit of Measure | Classifications |
|-------------------------------|---|------------------------|---|
| Atmosphere | Greenhouse Gas Emissions | Tonnes/GWh | CO2e |
| | Air Contaminant Emissions | Tonnes/GWh | Sulphur Dioxide |
| | | | Oxides of Nitrogen |
| | | | Carbon Monoxide |
| | | | Volatile Organic Compounds |
| | | | Fine Particulates: PM 2.5 (reported when data is available) |
| | | | Fine Particulates: PM 10 (reported when data is available) |
| | | | Fine Particulates: PM Total |
| Mercury | | | |
| Freshwater | Reservoir Aquatic Area | ha | Site C (Pumped Storage and Resource Smart if applicable/available) |
| | Affected Stream Length | km | Run-of-river and Site C (Pumped Storage and Resource Smart if applicable/available) |
| | Riparian Area | ha | Sum of riparian area per class based on stream order (Run-of-river, Pumped Storage, roads and power line crossings if applicable/available) |
| | Priority Fish Species (number of priority fish species per watershed) | ha per class | No Priority Species (0) |
| | | | Low Species Diversity (1 to 12) |
| | | | Moderate Species Diversity (13 to 23) |
| | | | High Species Diversity (24 to 38) |
| Marine | Bathymetry | ha per class | Photic (0 to < 20 m) |
| | | | Shallow (20 to 200 m) |
| | | | Deep (200 to 1000 m) |
| | | | Abyssal (> 1000 m) |
| | Valued Ecological Features (number of valued ecological features) | ha per class | None (0) |
| | | | Low (1 to 2) |
| | | | Medium (3 to 5) |
| | | | High (> 5) |
| | Key Commercial Bottom Fishing Areas | ha per class | No bottom fisheries |
| | | | 1 bottom fishery |
| | | | 2 to 3 bottom fisheries |
| | | | > 3 bottom fisheries |

1 The Resource Options Mapping (**ROMAP**) geographical information system (**GIS**)
2 was used to overlay the footprint of potential supply-side resource options onto the
3 B.C. land base and calculate the attributes (land, freshwater and marine) of the
4 footprint. For each potential supply-side resource option, the evaluated footprint
5 includes the 'at gate' plant area (**G**), and the associated new road (**R**) and new
6 transmission (**T**) corridors required to operate and link the plant to existing
7 infrastructures.

8 The environmental update has taken the approach of estimating the footprint of the
9 potential projects during their operation phase, aggregated into resource options
10 bundles or clusters.

11 These high-level environmental attributes and footprints are appropriate for
12 comparison of resource options across provincial-scale portfolios. Since detailed
13 site-specific information is unknown for the majority of the potential sites in the
14 database, these environmental attributes are not appropriate, or intended to be
15 used, for individual site-specific resource option evaluations and comparisons. The
16 2013 ROR Update presents a summary of the environmental attributes of resource
17 options in the Resource Options Database (**RODAT**) summary sheets of
18 Appendix 3.

19 **3.5 Economic Development Attributes**

20 The same economic development attributes developed for the 2010 ROR are used
21 to characterize the resource options. These attributes were selected based upon the
22 following criteria:

- 23 • Appropriate for provincial-scale portfolio comparisons;
- 24 • Address the government's *Clean Energy Act* objective with regard to economic
25 development and the creation and retention of jobs
- 26 • Measurable in a quantity-based approach that facilitate comparison between
27 portfolios of resource options

- 1 • Representative of accepted best practice in economic impact analysis
- 2 • Based on existing data or easily acquired data
- 3 • Easy to understand for long-range planning and stakeholder engagement
- 4 purposes

5 The economic development attributes are categorized into three economic groups:
 6 gross domestic product (**GDP**), employment, and government revenue and are
 7 further broken down into indicators described in [Table 3-3](#).

8 **Table 3-3 Economic Development Attributes**

| Economic Development Category | Sub-Category | Unit of Measure | Classifications |
|--------------------------------------|------------------------|------------------------|------------------------|
| Provincial GDP | Construction/Operation | \$ and \$/year | Direct |
| | | | Indirect |
| | | | Induced |
| Employment | Construction/Operation | Jobs | Direct |
| | | | Indirect |
| | | | Induced |
| Provincial Government Revenue | Construction/Operation | \$ and \$/year | Direct |
| | | | Indirect |
| | | | Induced |

9 Note: Jobs, sometimes referred to as person years (**PYs**), reflect the average jobs in the affected industries,
 10 which may not always be full-time. In general, construction jobs are shorter-term and higher in number, whereas
 11 operating jobs are longer-term and last the life expectancy of the project.

12 These high-level economic development attributes are appropriate for comparison of
 13 resource options across provincial-scale portfolios, but not appropriate, or intended
 14 to be used, for individual site specific resource option evaluations and comparisons.
 15 The 2013 ROR Update presents a summary of the economic development attributes
 16 of resource options in the RODAT summary sheets of Appendix 3.

17 A detailed account of the economic development attributes is presented in
 18 Appendix 4.

1 **3.6 Data Confidence**

2 The data assessed in the 2013 ROR Update have varying levels of confidence. The
 3 levels of confidence depend on the level of study, resource type related uncertainties
 4 and cost uncertainties. The criteria used to define the levels of confidence are
 5 summarized in [Table 3-4](#).

6 **Table 3-4 Levels of Data Confidence for Resource**
 7 **Options**

| Uncertainty | Rating | Criteria |
|-----------------------------------|-------------------------------------|---|
| Level of Study | Survey | First, or preliminary, level of study that typically uses data derived from existing sources to yield new general information. Does not thoroughly examine all the parameters related to specific projects or settings. The primary intent is to synthesize emerging patterns. Based on a preliminary methodology or analysis technique, may or may not be supported by documentation or research. |
| | Pre-feasibility | Secondary level of evaluation study that assesses the cost and extent of implementation and impact for a specific project or group of projects and usually identifies more detailed needs assessment. Evaluation studies tend to focus on site specific conditions and use a range of qualitative and quantitative tools. Clearly attempts to describe the specific project conditions and outcomes and provides sufficient contextual information for someone to generalize and possibly replicate the results. Pre-feasibility study results are usually used to determine if it is worthwhile to proceed to the feasibility study stage. |
| | Feasibility | A comprehensive evaluation study for a proposed project designed to identify the implications of carrying out a project, including the site-specific technical, financial, environmental and economic attributes and requirements of a proposed project. This level of study can include descriptive, quantitative and formal research designs. |
| Resource Type Related Uncertainty | Low, Medium, High | These ratings are applicable to the following: <ul style="list-style-type: none"> • Technology specific issues, e.g., maturity of technology, emerging technology hurdles, experimental prototype • Development experience, e.g., lack of B.C. based development experience, permitting hurdles, resource potential confirmation, exploration risks, competing resource uses, public acceptance |
| Cost Uncertainty | Low: -10 per cent / +20 per cent | Design-level studies or well-established site-specific information. Capital cost uncertainty estimated to be -10 per cent to +20 per cent unless specific range of cost uncertainty is available for specific project. |

Integrated Resource Plan Appendix 3A-1

| | | |
|--|---|--|
| | Medium: -10 per cent / +40 per cent | Feasibility-level studies or well-established non-site-specific information. Capital cost uncertainty estimated to be -10 per cent to +40 per cent unless a specified range of cost uncertainty is available for specific project. |
| | High: -10 per cent / +60 per cent | Pre-feasibility or conceptual-level studies or developing technologies. Capital cost uncertainty estimated to be -10 per cent to +60 per cent unless a specified range of cost uncertainty is available for specific project. |

2013 Resource Options Report Update

Chapter 4

Demand-Side Management Options

Table of Contents

| | | |
|---------|--|------|
| 4.1 | Introduction | 4-1 |
| 4.1.1 | Overview of DSM Options..... | 4-1 |
| 4.1.1.1 | Energy and Capacity Options | 4-2 |
| 4.1.1.2 | Capacity-Focused Options | 4-3 |
| 4.1.2 | Attributes of DSM..... | 4-4 |
| 4.1.2.1 | DSM Technical and Financial Attributes | 4-4 |
| 4.1.2.2 | DSM Environmental and Economic Development Attributes | 4-6 |
| 4.2 | Energy and Capacity DSM Options | 4-6 |
| 4.2.1 | Option 1 | 4-11 |
| 4.2.2 | Option 2 | 4-12 |
| 4.2.3 | Option 3 | 4-16 |
| 4.2.4 | Options 4 and 5..... | 4-17 |
| 4.2.4.1 | Option 4 Description | 4-17 |
| 4.2.5 | Electricity Savings and Costs Comparison | 4-21 |
| 4.3 | Capacity-Focused DSM Options..... | 4-26 |
| 4.3.1 | Industrial Load Curtailment..... | 4-26 |
| 4.3.1.1 | Description..... | 4-26 |
| 4.3.1.2 | Tactics | 4-27 |
| 4.3.2 | Capacity-Focused Programs..... | 4-27 |
| 4.3.2.1 | Description..... | 4-27 |
| 4.3.2.2 | Program Concepts..... | 4-27 |
| 4.3.3 | Capacity Savings and Costs Comparison..... | 4-28 |

List of Figures

| | | |
|------------|--------------------------------------|------|
| Figure 4-1 | Energy Savings..... | 4-22 |
| Figure 4-2 | Associated Capacity Savings..... | 4-23 |
| Figure 4-3 | Total Resource Costs | 4-24 |
| Figure 4-4 | Utility Costs | 4-25 |
| Figure 4-5 | Combined Capacity Savings (MW) | 4-29 |

List of Tables

| | | |
|------------|---|------|
| Table 4-1 | Levels of Data Confidence for DSM Options | 4-6 |
| Table 4-2 | Energy and Capacity DSM Options Comparison | 4-8 |
| Table 4-3 | Option 2: Codes and Standards..... | 4-14 |
| Table 4-4 | Option 2: Programs..... | 4-15 |
| Table 4-5 | Option 2: Supporting Initiatives | 4-16 |
| Table 4-6 | Option 5: Codes and Standards Changes | 4-19 |
| Table 4-7 | Option 5: Conservation Rate Structure Changes | 4-20 |
| Table 4-8 | Option 5: Program Changes | 4-21 |
| Table 4-9 | TRC and UC for Energy and Capacity DSM Options..... | 4-25 |
| Table 4-10 | Residential Program Concepts | 4-27 |
| Table 4-11 | Commercial Program Concepts | 4-28 |
| Table 4-12 | Industrial Program Concepts | 4-28 |
| Table 4-13 | TRC and UC for Capacity-Focused DSM Options | 4-29 |

1 **4.1 Introduction**

2 In a long-term resource planning context, BC Hydro looks at demand-side
3 management (**DSM**) as a resource option since the energy savings that come from
4 DSM initiatives reduce future load growth and therefore minimize the need for future
5 supply-side resources. Attributes of DSM considered in the resource planning
6 framework include relatively low cost, low environmental impact, and economic
7 benefits associated with job creation and contributions to provincial GDP. DSM is
8 also a flexible resource to a degree, meaning that it has some ability to be ramped
9 up or down based on the future need for resources.

10 Outside of a resource planning context, DSM has other important benefits to
11 BC Hydro and its customers. Specifically, it provides an opportunity for customers to
12 reduce their energy bills and an incentive to make energy efficient investment
13 decisions through cost-effective investments on both the customer and BC Hydro's
14 part.

15 **4.1.1 Overview of DSM Options**

16 At a high level, BC Hydro has developed two sets of DSM options: energy and
17 capacity options and capacity-focused options. BC Hydro's current DSM plan is
18 energy-focused, and is expected to deliver capacity savings as well. In contrast,
19 capacity-focused options are designed to deliver capacity savings, during
20 BC Hydro's peak load periods on the electrical system, through management and
21 control of a customer's electricity demand rather than energy consumption.

22 For the 2010 ROR, BC Hydro developed five energy and capacity DSM options
23 (DSM Options 1 through 5) and two¹ capacity-focused DSM options (industrial load
24 curtailment and capacity-focused programs). This 2013 ROR Update provides a
25 targeted update to energy and capacity Options 1, 2, and 3 to reflect new

¹ At the time of the 2010 ROR development BC Hydro also considered Time-Based Rates as a category of capacity resource option; since then, in accordance with government policy, BC Hydro has no plans to implement Time-Based Rates to address capacity requirements.

1 information on: 1) economic/market conditions: 2) customer participation; and
2 3) load forecast and economic conservation potential. Options 1, 2 and 3 have the
3 same parameters as in the 2010 ROR:

- 4 • BC Hydro's current DSM target of 7,800 GWh/year and 1,400 MW is DSM
5 Option 2, which was built from the DSM targets established in the 2008 LTAP
- 6 • Option 1 continues to be designed to meet the *CEA* energy objective of
7 reducing the increase in demand of electricity by at least 66 per cent by F2021
8 (per *CEA* subsection 2(b))
- 9 • Option 3 continues to target more electricity savings than Option 2 by
10 expanding program efforts while keeping the level of activity for codes and
11 standards, and conservation rate structures, consistent with Option 2

12 Energy and capacity Options 4 and 5 and capacity-focused options were not
13 updated for the 2013 ROR Update, because they have been found to not be viable
14 for long-term planning purposes at this time. While not updated for the 2013 ROR, a
15 description of these options is included here.

16 **4.1.1.1 Energy and Capacity Options**

17 The five energy and capacity DSM options are created as integrated packages of
18 DSM tools that are interrelated and employed in concert to achieve a particular path
19 of energy savings over time. The specific tools include codes and standards,
20 conservation rate structures and programs.

- 21 • Codes and standards are public policy instruments enacted by Federal,
22 Provincial and Municipal governments to influence energy efficiency. Examples
23 include building codes, energy efficiency regulations, tax measures, and local
24 government zoning and building permitting processes.
- 25 • Conservation rate structures are aimed at conserving energy, promoting energy
26 efficiency, or reducing the energy demand that BC Hydro must serve, such as

1 inclining block (stepped) rate structures. BC Hydro has conservation rates in
2 place (or with planned implementation) for over 90 per cent of its domestic load.
3 Over the past seven years, BC Hydro implemented four conservation rate
4 structures for residential, commercial, and industrial customers.

- 5 • Programs are designed to support the development of and address the
6 remaining barriers after codes and standards and rate structures and thereby
7 capture additional energy efficiency and conservation potential. Programs
8 include load displacement projects, which reduce the energy demand that
9 BC Hydro must serve as a result of existing customers self-supplying through
10 self-generation.

11 In addition, there are a number of supporting initiatives – public awareness and
12 education, community engagement, technology innovation, information technology,
13 and indirect and portfolio enabling – that provide a critical foundation for awareness,
14 engagement, and other conditions to support the success of BC Hydro’s DSM
15 initiatives.

16 In addition to these tactics, BC Hydro develops DSM options in consideration of a
17 strategic framework where DSM initiatives can be targeted to different contexts:
18 individual, market and social. While all DSM options include initiatives targeting
19 individual, market and social contexts, to reach higher levels of energy savings,
20 BC Hydro must rely on market and societal transformation to a greater degree.

21 **4.1.1.2 Capacity-Focused Options**

22 Capacity-focused DSM specifically targets capacity savings. Experience will need to
23 be gained to increase certainty of the expected capacity reductions. Two options
24 were developed as follows:

- 25 • **Industrial Load Curtailment:** This option targets large customers who agree to
26 curtail load on short notice to provide BC Hydro with capacity relief during peak
27 periods. BC Hydro has implemented a load curtailment program targeted at

1 shorter term (one to three years) operational capacity needs in recent years,
2 and customers have delivered as requested. However, it is not clear how easily
3 these can be translated into long-term agreements that can reliably reduce
4 peak demand over a longer-term.

- 5 • **Capacity-focused Programs:** This option contains programs that leverage
6 equipment and load management systems to enable peak load reductions to
7 occur automatically or with intervention. These voluntary programs may involve
8 payment for customer equipment and a financial payment for participation in the
9 program. Examples of capacity-focused programs include load control of water
10 heaters, heating, lighting and air conditioning. Thus capacity-focused programs
11 are a collection of several activities; both demand response and load control,
12 spread across different customer classes. The participation rate and savings
13 per participant are key aspects of the uncertainty of capacity savings.

14 **4.1.2 Attributes of DSM**

15 **4.1.2.1 DSM Technical and Financial Attributes**

16 The cost-effectiveness of DSM is determined by the Total Resource Cost (**TRC**) and
17 Utility Cost (**UC**) tests as described by the *California Standard Practice Manual:
18 Economic Analysis of Demand-Side Programs and Projects*,² (**California Standard
19 Practice Manual**).

- 20 • The TRC measures the overall economic efficiency of a DSM initiative from a
21 resource options perspective. In particular, the TRC measures the costs of a
22 DSM initiative based on the net costs of the initiative, including both participant
23 and utility costs. The benefits are the avoided supply costs – BC Hydro refers to
24 this result as the **gross TRC**. The California Standard Practice Manual and
25 many other jurisdictions also recognize that DSM results in a range of other
26 benefits, such as a reduction in capacity costs (generation, transmission and

² October 2001; available at the California Energy Commission's website at www.energy.ca.gov.

1 distribution), specific non-energy benefits (e.g., operation and maintenance
2 savings resulting from the installation of an energy efficient measure) and
3 avoided participant costs aside from electric utility bills (such as natural gas and
4 water savings) – BC Hydro refers to this result as the **net TRC**. Inclusion of
5 these benefits increases the cost-effectiveness of DSM. Except where
6 specifically noted, BC Hydro uses the net TRC.

- 7 • The UC measures the costs of the DSM initiative from the utility’s perspective,
8 excluding any costs of the participant. The benefits are similar to the TRC utility
9 benefits (avoided supply costs and capacity). The UC test result indicates the
10 change in total utility bills (revenue requirements) due to DSM.

11 The BCUC’s determination of DSM cost-effectiveness is also guided by the
12 Demand-Side Measures Regulation³ (**DSM Regulation**). The DSM Regulation
13 contains among other things modifications to the TRC test (referred to as the
14 **modified TRC**) that the BCUC must follow when assessing DSM expenditure
15 schedules submitted by public utilities pursuant to subsection 44.2(1)(a) of the
16 *Utilities Commission Act*. The DSM Regulation provides a deemed value for natural
17 gas savings and a deemed non-energy benefit adder of 15 per cent.

18 *DSM Amortization*

19 The DSM amortization period, which aligns DSM costs and benefits over time, uses
20 a 15-year period to reflect the average persistence of DSM program savings.

21 *Uncertainty and Risk*

22 The five energy and capacity DSM options described in this ROR provide insight into
23 the incremental DSM costs and uncertainties of pursuing additional quantities of
24 energy conservation. There are two main uncertainties with respect to DSM: cost

³ B.C. Reg. 228/2011.

1 and energy savings. [Table 4-1](#) summarizes the DSM option cost uncertainty
 2 confidence levels.

3 **Table 4-1 Levels of Data Confidence for DSM**
 4 **Options**

| | Resource Option | Resource Type Related Uncertainty Rating | Cost Uncertainty Rating |
|------------------------------------|-----------------------------|---|---|
| Energy and Capacity Options | Option 1 | Medium | Medium (-10 per cent / +40 per cent) |
| | Option 2 | Medium | Medium (-10 per cent / +40 per cent) |
| | Option 3 | Medium | Medium (-10 per cent / +40 per cent) |
| | Option 4 | High | Medium/High (-10 per cent / +50 per cent) |
| | Option 5 | High | High (-10 per cent / +60 per cent) |
| Capacity-Focused Options | Industrial Load Curtailment | Medium | Medium (-10 per cent / +40 per cent) |
| | Capacity-focused Programs | High | High (-10 per cent / +60 per cent) |

5 **4.1.2.2 DSM Environmental and Economic Development Attributes**

6 DSM has little to no environmental impact. As the impacts, if any, are negligible from
 7 a long-term resource planning perspective, they were not estimated for the
 8 2013 ROR.

9 Economic development attributes were updated for energy and capacity Options 1
 10 through 5 for the 2013 ROR.

11 **4.2 Energy and Capacity DSM Options**

12 As discussed earlier, BC Hydro conducted a targeted update of the DSM Options for
 13 the 2013 ROR. Specifically, Options 1, 2 and 3 have been updated to reflect new
 14 information on the cost and energy savings performance of the DSM tools
 15 (programs, codes and standards, conservation rate structures) and supporting
 16 initiatives:

1 As part of the first component of the update, BC Hydro updated the savings potential
2 to reflect new information, including economic/market conditions, customer
3 participation and a reduced 2012 mid-level Load Forecast as compared to the 2010
4 mid-level Load Forecast. In the 2008 LTAP proceeding, BC Hydro provided
5 evidence that a reduced load forecast impacts DSM economic potential.⁴ For
6 example, it is generally acknowledged that industrial DSM participation and energy
7 efficiency will increase during economic growth and decrease in recessionary
8 periods.⁵ In addition, different industries have varying economic and technical
9 potential to provide DSM based on specific equipment and processes. For example,
10 forestry likely has greater DSM potential than new oil and gas development or
11 mining.

12 The second component of the update looked at whether there was an ability to make
13 adjustments to the level of activity in the near term represented by the various DSM
14 options while still retaining the ability to ramp up to meet longer-term targets. As
15 DSM is a flexible resource, it can be reduced in the near-term and ramped up in later
16 years to meet long-term targets. As part of portfolio cost management efforts,
17 BC Hydro is interested in understanding how expenditures could be reduced in the
18 near-term while still retaining the ability to ramp up back to longer-term energy
19 savings targets. Programs and supporting initiatives are more flexible (have more
20 ability to be ramped up or down) in the near-term than codes and standards and
21 conservation rate structures, and therefore adjustments were targeted to programs
22 and supporting initiatives (i.e., in other words, codes and standards and
23 conservation rates were not reduced). BC Hydro explored Options 1, 2 and 3 for the
24 potential to be adjusted in the near term, and revised Option 1 and Option 2 to
25 reflect lower levels of expenditures in the near term. A version of Option 3 with
26 near-term reductions was not included in the analysis. Option 3 would only be
27 selected if needed to fill the resource gap beyond Option 2. If that higher resource

⁴ Exhibit B 10 in the 2008 LTAP proceeding, section 2.4.2.

⁵ See, for example, T.Ernst and O.Dancel, "Macroeconomic Impacts on DSM Program Participation", 2011 ACEEE Summer Study on Energy Efficiency in Industry), page 1-81.

1 level was required, BC Hydro would not reduce Option 3 expenditures in the
 2 near-term due to the deliverability risk in recovering to Option 3 savings levels
 3 (uncertainty with the ramp rate assumptions).

4 As a reference, [Table 4-2](#) below provides a high level description of each option,
 5 including how it was modified for the 2013 ROR and how it compares relative to the
 6 other options.

7 **Table 4-2 Energy and Capacity DSM Options**
 8 **Comparison**

| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|-------------|--|--|---|---|--|
| Description | Updated. A reduction from the current DSM plan (Option 2), delivering DSM savings to reduce the expected increase in demand for electricity by the year 2020 by at least 66 per cent, as called for in the Clean Energy Act (<i>CEA</i>). | Updated. BC Hydro's current DSM plan. The 2013 ROR Update reflects a reduction from previously planning expenditure levels of \$230M in the near term (F2015 to F2016) and then ramps up program activity moderately in F2017 to meet long-term targets. Expenditures are being maintained at a level consistent with the past few years. | Updated. Expands programs to the limit of cost-effectiveness, while keeping codes and standards and conservation rate structures the same as in Option 2. Updated to reflect new information since the 2010 ROR. | Not updated. Expands the codes and standards and conservation rate structure tools. Initial steps are added towards the tactics reflected in Option 5, with some programs scaled back or wound down as part of the transition. | Not updated. Reflects a comprehensive effort to change market parameters and societal norms and patterns in order to save electricity. It contains strong codes and standards and conservation rate structures. |

Integrated Resource Plan Appendix 3A-1

| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|----------|--|---|---|---|--|
| Programs | Programs expenditures were further reduced from Option 2 in the near term. | Program expenditures are reduced by ~50 per cent by F2016 and then are moderately increased starting in F2017 | Program expenditures are updated to reflect new information since the 2010 ROR. | Relative to Option 3, some programs are wound down earlier because of new codes and standards. Relative to Option 5, there are more incentives for commercial and industrial customers in the early years, because of less aggressive codes and standards activity. | In general, program incentives are eliminated or diminished by F2020 because of more aggressive codes and standards and rate structures. Some program incentives remain where there are cost barriers. |

Integrated Resource Plan Appendix 3A-1

| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|-------------------------------------|--|---|-------------------|---|--|
| Codes & Standards | In the 2010 ROR, Option 1 levels of effort were kept the same as Option 2. | Codes and standards that have been enacted, announced or planned by the federal and provincial governments. | Same as Option 2. | Additional or more aggressive codes and standards are included that are not currently planned by governments. Similar, but less aggressive actions compared to Option 5. | Additional or more aggressive codes and standards are included that are not currently planned by governments. More aggressive than Option 4 in the following areas: 1) residential and commercial retrofit code, 2) residential and commercial building code, 3) earlier introduction of equipment regulations. |
| Conservation Rate Structures | In the 2010 ROR, Option 1 levels of effort were kept the same as Option 2. | Estimates of future energy savings have been updated to reflect BC Hydro's current long-run marginal cost. | Same as Option 2. | Increased effort from Option 3 as follows: 1) large industrial customers – an increase in the amount of energy consumption that is subject to the higher Tier 2 price; 2) commercial customers - placeholder concept of tying rates to building energy performance. | Levels of effort are higher than Option 3. |

| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
|------------------------|---|--|--|---|--|
| Supporting Initiatives | Expenditures were further reduced from Option 2 in the near term. | Budget was reduced by ~30 per cent in the near term and then increased in F17. | Updated to reflect new information since the 2010 ROR. | Increased effort targeting market and societal change, resulting in more funding than Option 3. | Levels of effort are higher than Option 4. |

1 **4.2.1 Option 1**

2 In the 2010 ROR, Option 1 was developed explicitly to meet 66 per cent of the
 3 forecasted load growth with DSM, which would be the minimum required to meet the
 4 CEA Objective of reducing the expected increase “in demand for electricity by the
 5 year F2021 *by at least 66*” per cent [emphasis added]. The planning parameter for
 6 the updated Option 1 is similar to those in the 2010 ROR: reduce expected load
 7 growth by at least 66 per cent in F2021, and on average for the remaining portion of
 8 the planning period (F2022 to F2032). The updated Option 1 targets
 9 6,100 GWh/year of energy savings and 1,200 MW of associated capacity savings by
 10 F2021.

11 At the time of the 2010 ROR, the calculation of the amount of DSM required to
 12 reduce the expected increase in demand for electricity by F2021 by at least
 13 66 per cent was based on the 2010 Load Forecast. Based on the 2012 mid-level
 14 Load Forecast⁶ (the reference forecast for the 2013 IRP), load growth has declined
 15 such that a lower level of energy savings is required in F2021 to reduce the
 16 expected increase in demand by at least 66 per cent. Accordingly, BC Hydro
 17 updated Option 1 with the new load forecast information.

18 Option 1 also reflects adjustments to near-term expenditures. Specifically, the
 19 adjustments to expenditures reflect the lowest level of DSM possible while still being
 20 able to ramp up to meet the CEA Objective of reducing load growth by at least

⁶ Not including load from LNG.

1 66 per cent in F2021. By F2016, expenditures are reduced to a base level of
2 \$100 million. In F2021, energy savings just meet the 66 per cent objective. The level
3 of near-term expenditures is lower than in Option 2. To reach this lower level of
4 expenditures, additional adjustments were made to programs and supporting
5 initiatives in the following areas:

- 6 • Residential: Expenditures are reduced by a further 12 per cent by F2016
7 relative to Option 2 through targeted reductions to a few programs
- 8 • Commercial: Program expenditures are reduced by a further 24 per cent by
9 F2016 through limiting participation and reducing program costs for most
10 programs
- 11 • Industrial: Relative to the Option 2, program expenditures are reduced by
12 22 per cent in F2016 and 29 per cent in F2017. These reductions are achieved
13 through lower levels of activity in the load displacement program and other
14 programs.
- 15 • Supporting initiatives: an additional 19 per cent by F2016 was made to
16 supporting initiative expenditures

17 **4.2.2 Option 2**

18 In the 2010 ROR, Option 2 was an updated version of the DSM plan that was
19 included in BC Hydro's 2008 LTAP filing with the British Columbia Utilities
20 Commission (**BCUC**). The updated Option 2 target continues to be the 2008 LTAP
21 target, which is 7,800 GWh/year of energy savings and 1,400 MW of associated
22 capacity savings by F2021.

23 Option 2 was first updated to reflect new information, such as the 2012 mid-level
24 Load Forecast and current economic conditions. This provided a new baseline for
25 the energy savings potential for Option 2.

1 In addition, BC Hydro wanted to maintain the 2008 LTAP DSM target over the
2 long-term while exploring whether expenditures could be adjusted in the near-term
3 to manage energy portfolio costs. BC Hydro notes that Option 2 was constructed to
4 meet the following parameters: first, reduce expenditures in the near-term (F2014 to
5 F2016) and by doing so, reduce energy savings as well; second, ramp up to
6 generally return to LTAP energy savings levels in F2021; and third, generally remain
7 at the LTAP energy savings levels post F2021 within +/- 10 per cent.⁷ The near-term
8 adjustments result in a reduction of \$230 million (46 per cent for F2015 and F2016)
9 relative to the DSM plan in the F2012-F2014 Revenue Requirements Application,
10 and approximately \$330 million by F2022 in expenditures relative to the update to
11 the Option 2 baseline described above.

12 With regard to the specific tactics employed in Option 2:

- 13 • Codes and standards are those that have been enacted, announced or planned
14 by the federal and provincial governments as summarized in [Table 4-3](#).

⁷ Minor variances from LTAP energy savings levels (generally in the order of +/- 10 per cent) can be expected from year to year because of the “lumpiness” of elements in the DSM plan.

1

Table 4-3 Option 2: Codes and Standards

| | Residential | Commercial | Industrial |
|------------|---|--|--|
| Equipment | <ul style="list-style-type: none"> • Incandescent lamps • Standby power • Set-top boxes • External power supplies • Portable and room air conditioners • Battery chargers • Digital television adapters • Windows • Ceiling fans • Torchieres • Electric water heaters | <ul style="list-style-type: none"> • High intensity discharge lamps and ballasts • Packaged terminal air-conditioners • Ice-cube makers • Large air-conditioners • Traffic and pedestrian lights • Dry transformers • Fluorescent lamps | <ul style="list-style-type: none"> • Motors |
| Appliances | <ul style="list-style-type: none"> • Clothes washers • Refrigerators • Freezers • Dishwashers | <ul style="list-style-type: none"> • Clothes washers • Refrigeration | |
| Buildings | <ul style="list-style-type: none"> • B.C. Building Code • City of Vancouver building bylaw | <ul style="list-style-type: none"> • B.C. Building Code • City of Vancouver building bylaw | |

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- Conservation rate structures are those that are in place or planned. These include the Transmission Service Rate (**TSR**) for large industrial customers, the Residential Inclining Block (**RIB**) rate for residential customers, a conservation rate structure for large commercial and small industrial customers in the former Large General Service (**LGS**) rate class, and a conservation rate structure for the Medium General Service (**MGS**) rate class.
- Programs target residential, commercial and industrial customer classes. Programs were the primary lever for determining the near-term adjustments as provided in [Table 4-4](#)

1

Table 4-4 Option 2: Programs

| Program | Near-Term Adjustments |
|---|---|
| Residential | |
| Refrigerator Buy-Back | <ul style="list-style-type: none"> • Reduce market presence in F2014 • Return to market in F2020 |
| Lighting Appliances Electronics | <ul style="list-style-type: none"> • Combine the programs into a new Retail Program that targets the three product categories on a rotation basis and at a significantly reduced expenditure level |
| New Home | <ul style="list-style-type: none"> • Eliminate incentives in early F2015 • Maintain developer education component (through codes and standards) to enhance code compliance and builder/ developer relationship |
| Smart Meter Infrastructure In-Home Feedback (Web Portal & In-Home Devices) | <ul style="list-style-type: none"> • Defer in-home display • Continue to support Web Portal |
| Low Income | <ul style="list-style-type: none"> • Maintain provision of energy savings kits • Maintain current participation levels in Energy Conservation Assistance Program (ECAP), while looking for process improvements |
| Commercial | |
| Power Smart Partner and Product Incentive Program (PIP) | <ul style="list-style-type: none"> • Continue with both programs but combine application process and IT infrastructure • Cap incentive funding • Reduce funding for energy study and energy managers. • Eliminate screw-in category and short savings persistence opportunities • Continue existing continuous optimization activities but reduce new participants • Future continuous optimization contract renewals would be offered on a shorter term to maintain flexibility and limit new growth • Defer customer Voltage and VAR Optimization (VVO) opportunities |
| New Construction | <ul style="list-style-type: none"> • Continue with program but find cost reductions • Eliminate short persistence technologies |
| Lead By Example | <ul style="list-style-type: none"> • Reduced employee engagement and re-scoped projects • Maintain policy activities |
| Industrial | |
| Power Smart Partner – Transmission | <ul style="list-style-type: none"> • Screen projects over \$1 million; eliminate incentive offer for projects over \$5 million • Cap incentive offer • Cap annual incentive funding and energy managers |
| Power Smart Partner – Distribution | <ul style="list-style-type: none"> • Eliminate least cost effective end uses and short persistence projects • Cap incentive funding • Increase performance metrics for energy managers |
| Load Displacement | <ul style="list-style-type: none"> • Continue with committed projects • Defer new projects to F2019 |

- Supporting Initiatives expenditures are reduced over the near term to align with program levels of activity. Activities are re-prioritized to focus on understanding the potential for new energy efficient technologies over the longer term.

Option 2 supporting initiatives are summarized in [Table 4-5](#).

Table 4-5 Option 2: Supporting Initiatives

- Public Awareness and Education lays a foundation of general awareness and understanding of the importance of electricity conservation among British Columbians and ultimately to build and sustain a culture of conservation. Community Engagement helps to overcome awareness and acceptance barriers to energy efficiency through community-based social marketing and to capture opportunities to save electricity through changes to local government planning and policy.
- Technology Innovation introduces new energy efficient technologies to B.C. and accelerates their commercialization and adoption in the Province. Information Technology supports the successful operation of selected DSM initiatives
- Indirect and Portfolio Enabling supports BC Hydro's DSM programs and activities with general management and infrastructure

Finally, the energy savings for revised Option 2 were adjusted for uncertainty.

4.2.3 Option 3

In the 2010 ROR, Option 3 was constructed to target more electricity savings by expanding program efforts, while keeping the level of activity and savings for codes and standards and conservation rate structures consistent with Option 2. Program activities are expanded with increased incentives, advertising or technical support to address customer barriers, thereby increasing customer participation. For the 2013 IRP, Option 3 is based on a similar construct. Program activity is expanded based on allowing program incremental cost-effectiveness to increase beyond BC Hydro's current Long Run Marginal Cost. The updated Option 3 targets 8,300 GWh/year of energy savings and 1,500 MW of associated capacity savings by F2021.

BC Hydro updated Option 3 to reflect new information on program performance in terms of updated assumptions on program costs and energy savings. Energy savings are lower than the 2010 ROR Option 3 because of reduced potential in incremental savings based on new information regarding the cost and energy

1 savings performance of the DSM tools. Codes and standards, and conservation rate
2 structures, reflect the same level of activity as updated Option 2 described above in
3 section 4.2.2.

4 **4.2.4 Options 4 and 5**

5 **4.2.4.1 Option 4 Description**

6 Options 4 and 5 were designed in collaboration with BC Hydro's Electricity
7 Conservation and Efficiency Advisory Committee (**EC&E**) and were intended to look
8 at a fundamental shift in BC Hydro's approach to saving electricity. These options
9 place much greater emphasis on tactics that change market parameters and societal
10 norms and patterns that influence electricity consumption and conservation. As new
11 and untested approaches to saving electricity, both Option 4 and Option 5 are
12 subject to considerable uncertainty regarding government, customer and BCUC
13 acceptance and, ultimately, their effectiveness at generating additional cost-effective
14 electricity savings.

15 BC Hydro did not update Options 4 and 5 at this time because they are currently not
16 technically viable options.

17 *Option 4*

18 DSM Option 4 is founded on new or more aggressive conservation rate structures,
19 and significant government regulation in the form of codes and standards, to
20 generate additional savings. Option 4 targets about 9,500 GWh/year of energy
21 savings and 1,500 MW of associated dependable capacity savings by F2021. Large
22 Industrial customers would be exposed to a much larger degree to marginal cost
23 price signals because the TSR would change from a 90/10 to an 80/20 split between
24 Tier 1 and Tier 2 prices, thereby increasing the amount of energy consumption that
25 is subject to Tier 2 pricing. Each industrial customer would need to meet a
26 government mandated certified plant minimum efficiency level to take advantage of
27 BC Hydro's Heritage hydroelectric lower priced electricity; otherwise, electricity

1 would be supplied at marginal (market-based) rates. Commercial customers would
2 be subject to efficiency-based pricing through either a connection fee tied to building
3 energy performance or an initial baseline rate structure for new buildings. Rate
4 structures may also need to be tied to a house or building's rated energy
5 performance.

6 *Option 5*

7 Option 5 is the most aggressive DSM option considered by BC Hydro. Option 5
8 targets about 9,600 GWh/year of energy savings and 1,600 MW of associated
9 dependable capacity savings by F2021. This option aims to create a future where
10 buildings are net-zero consumers of electricity with some buildings being net
11 contributors of electricity back to the grid. Energy efficiency and conservation
12 activities are pervasive throughout society and ingrained in a business decision
13 making culture. This shift is reflected through wide-spread district energy systems
14 and micro distributed generation, smaller more efficient housing and building
15 footprints, community densification, distributed workforce and hotelling (shared
16 workspace), best practices in construction and renovation, efficient technology
17 choices and behaviour, and an integrated community perspective (land-use, zoning,
18 multi-use areas). A carbon neutral public sector contributes to the culture shift. All
19 BC Hydro customers would be exposed to marginal cost price signals to a greater
20 extent. For the industrial sector, a market transformation to certified plants occurs,
21 supported with expanded regulation.

22 *Codes & Standards*

23 [Table 4-6](#) summarizes the Option 5 codes and standards changes relative to
24 Option 4. Additional or more aggressive codes and standards are included that are
25 not currently planned by governments.

1

Table 4-6 Option 5: Codes and Standards Changes

| | |
|------------|--|
| Community | <ul style="list-style-type: none"> • Residential building code changed to EnerGuide 90 in F2022 and net zero electricity in F2032, requiring distributed generation • Commercial building code strengthened by 15 per cent every five years, reaching net zero electricity in F2032, requiring distributed generation • Residential retrofit code introduced in F2021 and strengthened in F2032, requiring home owners to undertake specific energy saving measures during major renovations • Commercial retrofit code introduced in F2018 and strengthened in F2022, requiring building owners to undertake specific energy saving measures during renovations • Equipment regulations strengthened and broadened to cover additional equipment between F2015 and F2025 |
| Industrial | <p>2020</p> <ul style="list-style-type: none"> • New efficiency regulations in place for a selection of equipment • Industrial engineering firms are required to be certified under ISO energy management system standard • System End-Use-Intensity regulation in place <p>2030</p> <ul style="list-style-type: none"> • 75 per cent to 100 per cent of the industrial sectors are regulated to meet efficiency minimums • Efficiency regulations in place for mechanical pulping and hard rock grinding |

2 *Conservation Rate Structures*

3 Relative to Option 4, for conservation rate structures, changes are made to deliver
 4 even stronger price signals across customer classes.

5 [Table 4-7](#) summarizes the Option 5 conservation rate structure changes.

1
2

Table 4-7 Option 5: Conservation Rate Structure Changes

| | |
|-------------|--|
| Residential | <p>Two placeholder concepts are considered for implementation, with modelled savings based on the first concept:</p> <ul style="list-style-type: none"> • Two-part rate structure similar to the LGS rate assumed to start in F2016, with all customers seeing a marginal cost price signal which includes transmission and distribution costs • Rate structure tied to the efficiency of the home |
| Commercial | <p>One or more of the following concepts are introduced:</p> <ul style="list-style-type: none"> • A more aggressive LGS two-part rate • Increased marginal costs to include transmission and distribution costs • Marginal cost based rate for all consumption, with a credit for customers based on their participation in DSM programs • For existing buildings, a rate tied to electricity intensity that is differentiated by sector (kWh/unit) • For new buildings, a rate tied to the building’s rated energy performance • Connection fee tied to energy efficiency |
| Industrial | <p>TSR changed in F2020 (e.g., 80/20 or continuous step). End-Use Intensity rate assumed to start in F2032. Customers must meet Certified Plant minimum efficiency levels to receive the advantage of heritage priced electricity from BC Hydro. Otherwise, electricity is supplied at market-based rates.</p> |

3 *Programs*

4 As summarized in [Table 4-8](#), Option 5 includes the following program changes from
5 Option 2.

1

Table 4-8 Option 5: Program Changes

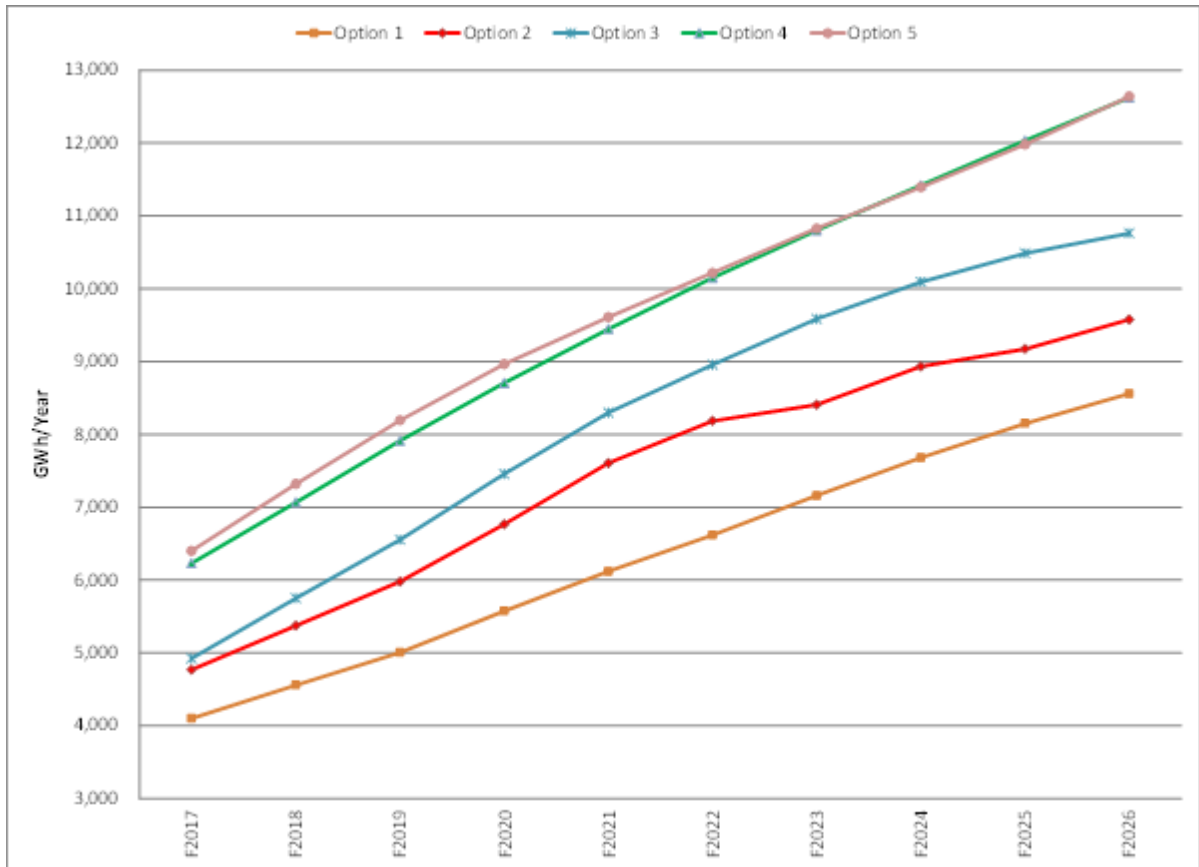
| | |
|------------|--|
| Community | <ul style="list-style-type: none"> • Program incentives eliminated or diminished around F2020 after two-part rate structures have been in place, at which time customer awareness of the rate structures should be high and a driver of customer energy decisions • Other program activities (e.g., advertising and enabling) are consolidated in F2020 into sector-wide efforts that help customers to respond to the rate structure price signals and focus on capacity building, channel engagement and awareness, and education and advocacy • Selected program incentives are retained to support the shift: <ul style="list-style-type: none"> – For large capital investments that will continue to face significant up-front capital cost barriers (e.g., new construction, major retrofits, solar photovoltaic, district energy) – For selected higher cost technologies that set the stage for codes and standards (e.g., heat pump clothes dryers) – Broaden direct install programs in residential and commercial |
| Industrial | <ul style="list-style-type: none"> • Programs change to integrate with ISO 50001 Energy Management System Standard and Industrial Plant Certification • Basis for program incentives shift from project costs to the value of electricity in F2020, but then diminish over time as rate structures and codes and standards take over as drivers of energy efficiency investments. • Program enabling activities continue. |

2 **4.2.5 Electricity Savings and Costs Comparison**

3 [Figure 4-1](#) compares the energy savings obtained from the five energy and capacity
 4 DSM options over the time horizon of the analysis.

1

Figure 4-1 Energy Savings⁸

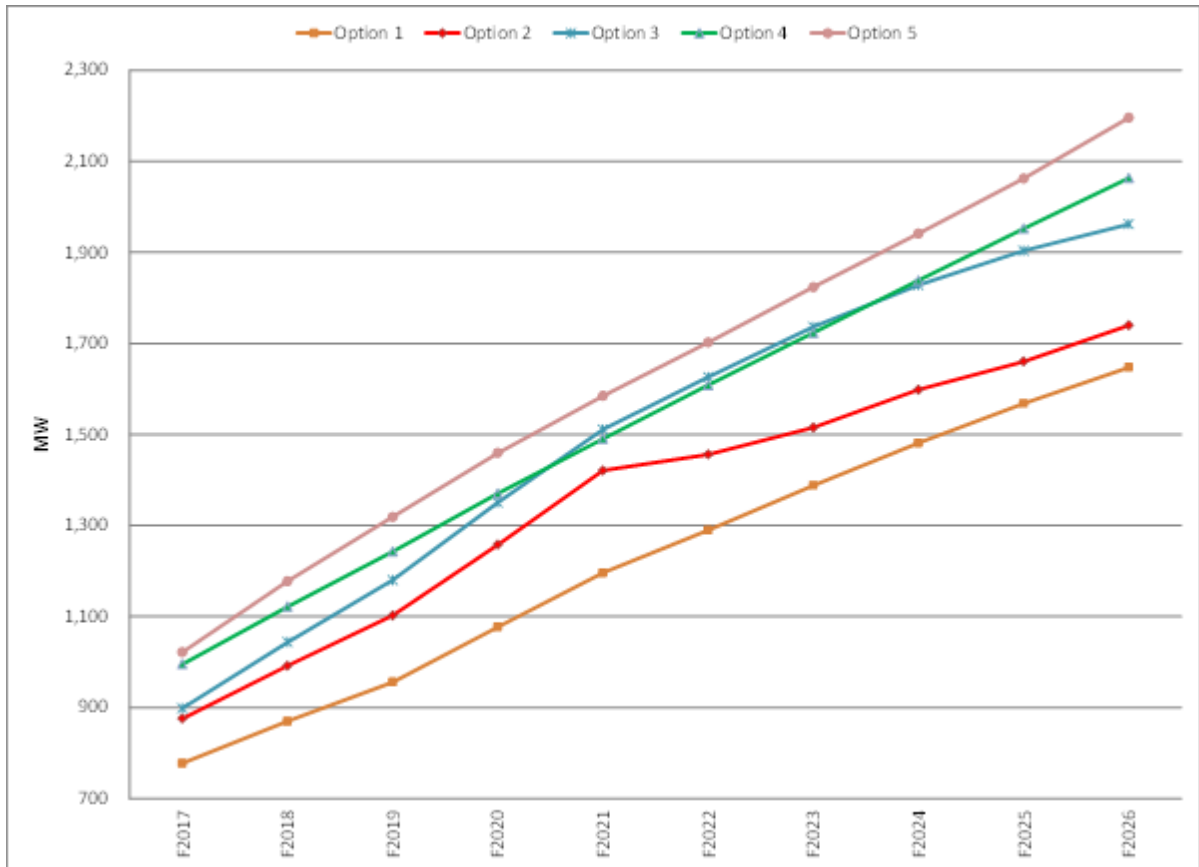


2 The associated capacity savings from the energy and capacity DSM options are
 3 provided in [Figure 4-2](#).

⁸ The energy savings shown for Options 1 through 5 have been adjusted for uncertainty.

1

Figure 4-2 Associated Capacity Savings⁹

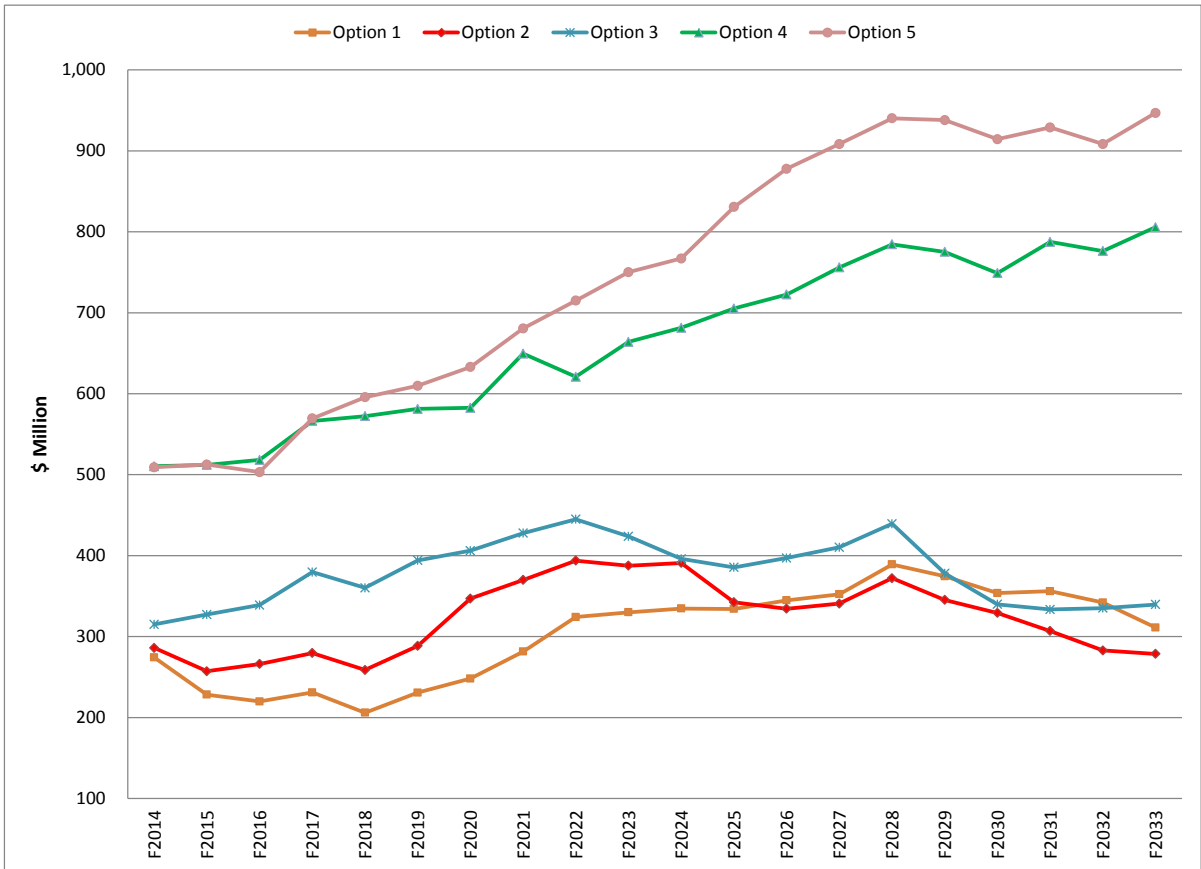


2 [Figure 4-3](#) and [Figure 4-4](#) show the resource investment TRC and UC in DSM for
 3 the various options.

⁹ The capacity savings shown for Options 1 through 5 have been adjusted for uncertainty.

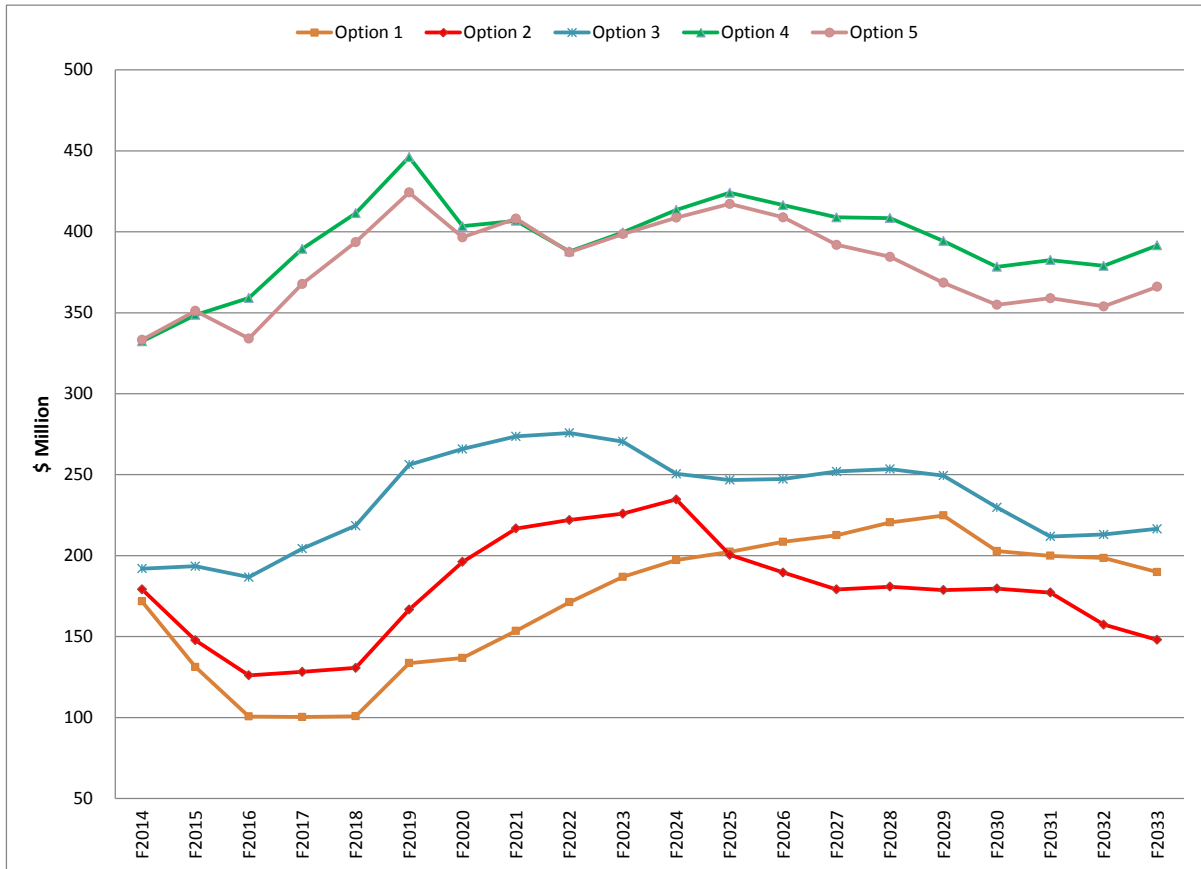
1

Figure 4-3 Total Resource Costs



1

Figure 4-4 Utility Costs



2 The unit energy costs from TRC and UC perspectives for each of the five energy
 3 and capacity DSM options are provided in [Table 4-9](#).

4 **Table 4-9 TRC and UC for Energy and Capacity**
 5 **DSM Options**

| Energy and capacity Option | TRC (\$/MWh) | UC (\$/MWh) |
|----------------------------|--------------|-------------|
| 1 | 32 | 18 |
| 2 | 32 | 18 |
| 3 | 35 | 22 |
| 4 | 47 | 30 |
| 5 | 49 | 29 |

1 **4.3 Capacity-Focused DSM Options**

2 While the energy and capacity options described earlier generate associated
3 capacity savings, additional capacity savings are achievable through
4 capacity-focused DSM, which targets capacity savings specifically. BC Hydro did not
5 update the capacity-focused DSM options for the 2013 ROR, but may start to
6 explore them in more detail pending the recommended actions from the IRP.

7 This list of options represents BC Hydro’s first major exploration of capacity-focused
8 DSM, and as a result, experience will need to be gained to increase certainty of the
9 expected electricity savings.

10 **4.3.1 Industrial Load Curtailment**

11 **4.3.1.1 Description**

12 Industrial load curtailment targets large customers who agree to curtail load on short
13 notice in return for a financial payment. BC Hydro had a load curtailment offer in
14 place from 2007 to 2010 as an operational contingency in the event of emergency
15 shortages. BC Hydro called on curtailment load twice during that time period and
16 customers curtailed as expected. The load curtailment offer was discontinued to new
17 customers for the 2010/2011 winter season due to a forecast surplus of peak
18 capacity in the BC Hydro system.

19 In this option, BC Hydro would institute a long-term load curtailment offer and rely on
20 the forecast peak demand reductions for the purpose of resource planning
21 (compared to the previous offer which was utilized to address short-term
22 contingencies). In effect, BC Hydro would scale its system to meet something less
23 than 100 per cent of forecast peak demand and plan to rely on industrial load
24 curtailment on the rare occasions when load exceeded capacity.

25 BC Hydro also has an industrial Modified Demand Rate as part of the existing TSR
26 which is designed to limit demand during morning and evening peak periods. A

1 redesign of this voluntary Modified Demand Rate is being investigated for its
 2 potential to increase capacity savings during the evening peak only.

3 **4.3.1.2 Tactics**

4 For this option, the agreement and financial payment could take a variety of forms
 5 (e.g., contract or rates) and a penalty could be applied for non-performance by
 6 participating customers.

7 **4.3.2 Capacity-Focused Programs**

8 **4.3.2.1 Description**

9 This option comprises a suite of programs that target capacity savings in all three
 10 customer sectors. They are designed to provide capacity savings that can be
 11 dispatched under utility control. Programs may involve payment for customer
 12 equipment and a financial payment for participation in the program. This could
 13 complement time-based rates by helping customers to respond to peak and off-peak
 14 price signals. In addition, as smart appliances are introduced with the capability to
 15 communicate with smart meters, new capacity-focused opportunities are expected.

16 **4.3.2.2 Program Concepts**

17 The key concepts for the capacity-focused residential ([Table 4-10](#)), commercial
 18 ([Table 4-11](#)) and industrial ([Table 4-12](#)) programs are outlined below.

19 **Table 4-10 Residential Program Concepts**

| | |
|--------------------------------------|--|
| Water heater control | Equipment provided and installed by utility automatically controls the on/off operation of the water heater. A one-time payment is provided to participants. |
| Thermostat or switch controlled heat | Equipment provided and installed by utility automatically controls the on/off operation of space heating equipment through a programmable thermostat or switch. A one-time payment is provided to participants. |
| Switch controlled radiant heat | Equipment incented by utility is purchased and installed and operated during off-peak periods to store heat. Stored heat is extracted and delivered to residence during on-peak times. A one-time payment is provided to participants. |

1

Table 4-11 Commercial Program Concepts

| | |
|---------------------------------------|---|
| Energy management system load control | Equipment receives a signal from the utility through the smart meter or other communication device that automatically controls the on/off operation of identified end use equipment during curtailment periods. An incentive payment is provided to participants based on proven load control capability. |
| Lighting control | Equipment provided and installed by utility automatically controls the voltage of power being supplied to the lighting system during curtailment periods. Lighting voltage can be reduced with no apparent reduction in lighting level. An incentive payment is provided to participants based on proven load control capability. |
| Water heater load control | Equipment provided and installed by utility automatically controls the on/off operation of water heaters during curtailment periods. An incentive payment is provided to participants based on participation. |
| Thermostat or switch controlled heat | Equipment provided and installed by utility automatically controls the on/off operation of the space heating equipment through a programmable thermostat or switch. An incentive payment is provided to participants based on participation. |
| Air conditioning load control | Equipment provided and installed by utility automatically controls the on/off operation of air conditioning during curtailment periods. An incentive payment is provided to participants based on participation. |

2

Table 4-12 Industrial Program Concepts

| | |
|--|--|
| Direct load control for distribution-level customers | Audits and potential incentives are provided to customers to install equipment and participate in offering load curtailment. Target end-uses are customer dependent (e.g., water heating, lighting). |
|--|--|

3

4.3.3 Capacity Savings and Costs Comparison

4

[Figure 4-5](#) provides a view of the potential combined capacity savings for the

5

capacity-focused options over the time horizon of the analysis. While the capacity

6

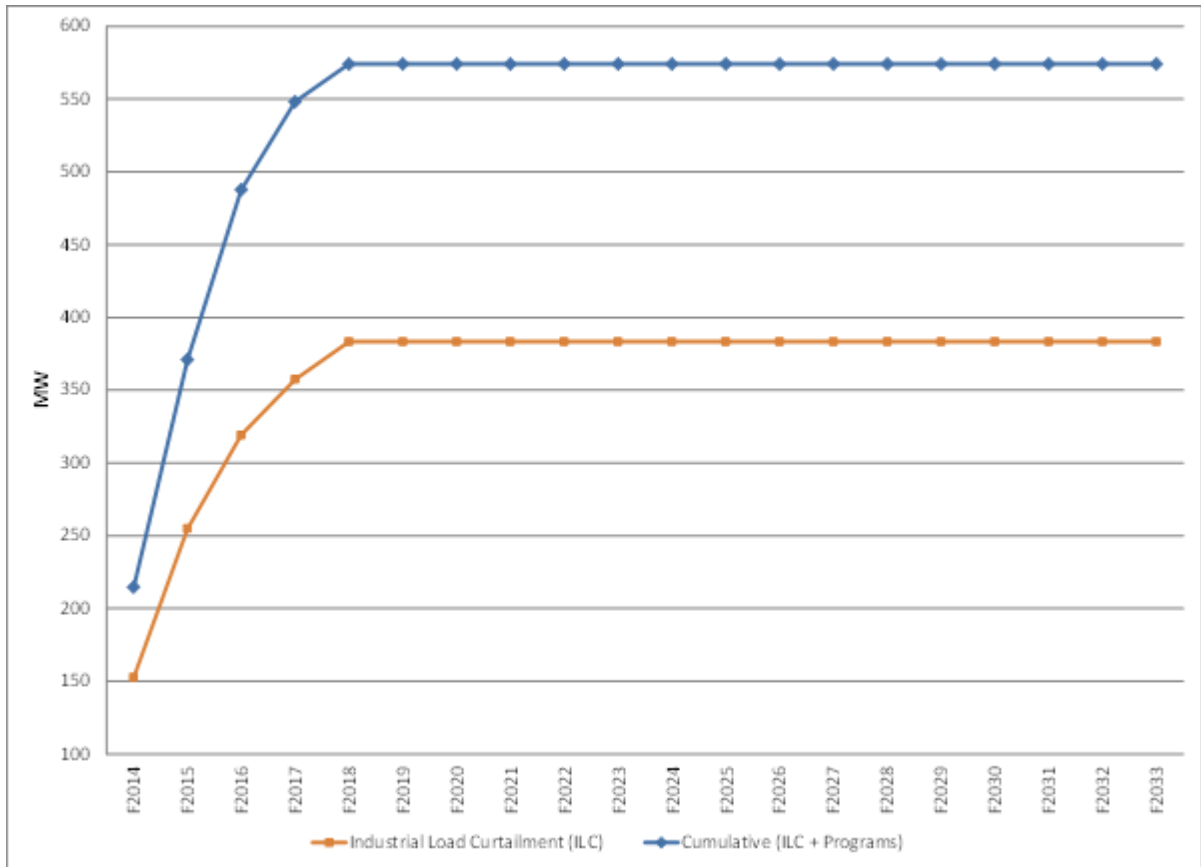
programs are independent, the curves for each option are overlaid onto the previous

7

option to provide an overview of the potential combined savings.

1

Figure 4-5 Combined Capacity Savings (MW)



2 The unit capacity costs from TRC and UC perspectives for each of the
 3 capacity-focused DSM options are provided in [Table 4-13](#).

4 **Table 4-13 TRC and UC for Capacity-Focused DSM**
 5 **Options**

| Capacity-focused Option | TRC * (\$/kw-year) | UC * (\$/kw-year) |
|-----------------------------|-----------------------|----------------------|
| Industrial Load Curtailment | 31 | 45 |
| Capacity-Focused Programs | 55 | 69 |

6 * Includes transmission and distribution loss savings estimates

2013 Resource Options Report Update

Chapter 5

Supply-Side Resource Options

Table of Contents

| | | |
|---------|---|------|
| 5.1 | Introduction | 5-1 |
| 5.1.1 | RODAT & ROMAP Databases..... | 5-1 |
| 5.1.2 | Resource Options Filters | 5-4 |
| 5.2 | Generation Resource Options..... | 5-8 |
| 5.2.1 | Wood Based Biomass – Standing Timber, Road Side and Sawmill Wood Waste | 5-8 |
| 5.2.1.1 | Resource Description | 5-8 |
| 5.2.1.2 | Methodology | 5-9 |
| 5.2.1.3 | Results..... | 5-11 |
| 5.2.1.4 | Environmental and Economic Development Attributes | 5-14 |
| 5.2.1.5 | Seasonality and Intermittence | 5-14 |
| 5.2.1.6 | Earliest In-Service Date | 5-15 |
| 5.2.1.7 | Uncertainty | 5-15 |
| 5.2.2 | Biomass – Biogas (Landfill) | 5-15 |
| 5.2.2.1 | Resource Description | 5-15 |
| 5.2.2.2 | Methodology | 5-17 |
| 5.2.2.3 | Technical and Financial Results | 5-19 |
| 5.2.2.4 | Environmental and Economic Development Attributes | 5-20 |
| 5.2.2.5 | Earliest In-Service Date | 5-20 |
| 5.2.2.6 | Seasonality and Intermittence | 5-20 |
| 5.2.2.7 | Uncertainty | 5-21 |
| 5.2.3 | Biomass – Municipal Solid Waste | 5-21 |
| 5.2.3.1 | Resource Description | 5-21 |
| 5.2.3.2 | Methodology | 5-23 |
| 5.2.3.3 | Technical and Financial Results | 5-26 |
| 5.2.3.4 | Environmental and Economic Development Attributes | 5-28 |
| 5.2.3.5 | Earliest In-Service Date | 5-28 |
| 5.2.3.6 | Seasonality and Intermittence | 5-28 |
| 5.2.3.7 | Uncertainty | 5-28 |
| 5.2.4 | Onshore Wind | 5-28 |
| 5.2.4.1 | Resource Description | 5-28 |
| 5.2.4.2 | Methodology | 5-29 |
| 5.2.4.3 | Technical and Financial Results | 5-31 |

| | | | |
|-------|---------|--|------|
| | 5.2.4.4 | Environmental and Economic Development Attributes | 5-32 |
| | 5.2.4.5 | Earliest In-Service Date | 5-32 |
| | 5.2.4.6 | Seasonality and Intermittence | 5-32 |
| | 5.2.4.7 | Uncertainty | 5-33 |
| 5.2.5 | | Offshore Wind | 5-33 |
| | 5.2.5.1 | Resource Description | 5-33 |
| | 5.2.5.2 | Methodology | 5-34 |
| | 5.2.5.3 | Technical and Financial Results | 5-35 |
| | 5.2.5.4 | Environmental and Economic Development Attributes | 5-36 |
| | 5.2.5.5 | Earliest In-Service Date | 5-36 |
| | 5.2.5.6 | Seasonality and Intermittence | 5-36 |
| | 5.2.5.7 | Uncertainty | 5-37 |
| 5.2.6 | | Geothermal Potential | 5-37 |
| | 5.2.6.1 | Resource Description | 5-38 |
| | 5.2.6.2 | Methodology | 5-41 |
| | 5.2.6.3 | Technical and Financial Results | 5-43 |
| | 5.2.6.4 | Environmental and Economic Development Attributes | 5-45 |
| | 5.2.6.5 | Earliest In-Service Date | 5-45 |
| | 5.2.6.6 | Seasonality and Intermittence | 5-46 |
| | 5.2.6.7 | Uncertainty | 5-46 |
| 5.2.7 | | Run-of-River | 5-47 |
| | 5.2.7.1 | Resource Description | 5-48 |
| | 5.2.7.2 | Methodology | 5-48 |
| | 5.2.7.3 | Technical and Financial Results | 5-52 |
| | 5.2.7.4 | Environmental and Economic Development Attributes | 5-54 |
| | 5.2.7.5 | Earliest In-Service Date | 5-54 |
| | 5.2.7.6 | Seasonality and Intermittence | 5-55 |
| | 5.2.7.7 | Uncertainty | 5-56 |
| 5.2.8 | | Pumped Storage | 5-56 |
| | 5.2.8.1 | Resource Description | 5-56 |
| | 5.2.8.2 | Methodology | 5-57 |
| | 5.2.8.3 | Technical and Financial Results | 5-57 |
| | 5.2.8.4 | Environmental and Economic Development Attributes | 5-58 |
| | 5.2.8.5 | Earliest In-Service Date | 5-59 |

| | | | |
|--------|----------|---|------|
| | 5.2.8.6 | Seasonality and Intermittence | 5-59 |
| | 5.2.8.7 | Uncertainty | 5-59 |
| 5.2.9 | | Large Hydro - Site C | 5-59 |
| | 5.2.9.1 | Resource Description | 5-59 |
| | 5.2.9.2 | Methodology | 5-60 |
| | 5.2.9.3 | Technical and Financial Attributes | 5-60 |
| | 5.2.9.4 | Environmental and Economic Development Attributes | 5-61 |
| | 5.2.9.5 | Earliest In-Service Date | 5-61 |
| | 5.2.9.6 | Seasonality and Intermittence | 5-62 |
| | 5.2.9.7 | Uncertainty | 5-62 |
| 5.2.10 | | Resource Smart | 5-62 |
| | 5.2.10.1 | Resource Description | 5-62 |
| | 5.2.10.2 | Methodology | 5-64 |
| | 5.2.10.3 | Technical and Financial Attributes | 5-64 |
| | 5.2.10.4 | Environmental and Economic Development Attributes | 5-65 |
| | 5.2.10.5 | Earliest In-Service Date | 5-65 |
| | 5.2.10.6 | Seasonality and Intermittence | 5-65 |
| | 5.2.10.7 | Uncertainty | 5-65 |
| 5.2.11 | | Natural Gas-Fired Generation and Cogeneration | 5-65 |
| | 5.2.11.1 | Resource Description | 5-66 |
| | 5.2.11.2 | Methodology | 5-67 |
| | 5.2.11.3 | Technical and Financial Results | 5-67 |
| | 5.2.11.4 | Environmental and Economic Development Attributes | 5-69 |
| | 5.2.11.5 | Earliest In-Service Date | 5-69 |
| | 5.2.11.6 | Seasonality and Intermittence | 5-70 |
| | 5.2.11.7 | Uncertainty | 5-70 |
| 5.2.12 | | Coal-Fired Generation with Carbon Capture and Sequestration..... | 5-70 |
| | 5.2.12.1 | Resource Description | 5-70 |
| | 5.2.12.2 | Methodology | 5-71 |
| | 5.2.12.3 | Technical and Financial Results | 5-71 |
| | 5.2.12.4 | Environmental and Economic Development Attributes | 5-72 |
| | 5.2.12.5 | Earliest In-Service Date | 5-72 |
| | 5.2.12.6 | Seasonality and Intermittence | 5-73 |
| | 5.2.12.7 | Uncertainty | 5-73 |

| | | |
|----------|--|-------|
| 5.2.13 | Wave..... | 5-73 |
| 5.2.13.1 | Resource Description | 5-73 |
| 5.2.13.2 | Methodology | 5-75 |
| 5.2.13.3 | Technical and Financial Results | 5-76 |
| 5.2.13.4 | Environmental and Economic Development Attributes | 5-77 |
| 5.2.13.5 | Earliest In-Service Date | 5-77 |
| 5.2.13.6 | Seasonality and Intermittence | 5-77 |
| 5.2.13.7 | Uncertainty | 5-78 |
| 5.2.14 | Tidal..... | 5-79 |
| 5.2.14.1 | Resource Description | 5-79 |
| 5.2.14.2 | Methodology | 5-80 |
| 5.2.14.3 | Technical and Financial Results | 5-81 |
| 5.2.14.4 | Environmental and Economic Development Attributes | 5-83 |
| 5.2.14.5 | Earliest In-Service Date | 5-83 |
| 5.2.14.6 | Seasonality and Intermittence | 5-83 |
| 5.2.14.7 | Uncertainty | 5-84 |
| 5.2.15 | Hydrokinetic | 5-84 |
| 5.2.15.1 | Methodology | 5-85 |
| 5.2.16 | Storage Technologies | 5-85 |
| 5.2.16.1 | Resource Description | 5-85 |
| 5.2.16.2 | Methodology | 5-88 |
| 5.2.17 | Solar | 5-89 |
| 5.2.17.1 | Resource Description | 5-89 |
| 5.2.17.2 | Methodology | 5-91 |
| 5.2.17.3 | Technical and Financial Results | 5-92 |
| 5.2.17.4 | Environmental and Economic Development Attributes | 5-94 |
| 5.2.17.5 | Earliest In-Service Date | 5-94 |
| 5.2.17.6 | Seasonality and Intermittence | 5-94 |
| 5.2.17.7 | Uncertainty | 5-95 |
| 5.2.18 | Miscellaneous Distributed Generation | 5-96 |
| 5.2.18.1 | Resource Description | 5-96 |
| 5.2.18.2 | Methodology | 5-98 |
| 5.2.19 | Other Capacity Options..... | 5-98 |
| 5.2.20 | Nuclear | 5-98 |
| 5.2.21 | Generation Resource Potential Results Summary..... | 5-98 |
| 5.3 | Bulk Transmission Resource Options | 5-115 |

| | | |
|-------|--|-------|
| 5.3.1 | Transmission Paths, Cut-Planes, and Congestion..... | 5-115 |
| 5.3.2 | Bulk Transmission Options | 5-117 |
| 5.3.3 | Transmission Expansion Projects | 5-120 |
| 5.3.4 | Regional Transmission Projects..... | 5-121 |
| 5.3.5 | Transmission for Export | 5-122 |
| 5.3.6 | Transmission for Interconnecting Individual New Resources... | 5-123 |
| 5.4 | Comparison to the 2010 ROR..... | 5-125 |

List of Figures

| | | |
|-------------|--|------|
| Figure 5-1 | Components (G, R, T) of the Resource Options Evaluated to the POI..... | 5-2 |
| Figure 5-2 | Ten Transmission Planning Regions | 5-4 |
| Figure 5-3 | Wood Based Biomass POI Supply Curves | 5-14 |
| Figure 5-4 | Biogas POI Supply Curves | 5-20 |
| Figure 5-5 | Biomass MSW POI Supply Curves | 5-27 |
| Figure 5-6 | Onshore Wind POI Supply Curves..... | 5-32 |
| Figure 5-7 | Normalized Monthly Onshore Wind Energy Profiles by Transmission Region | 5-33 |
| Figure 5-8 | Offshore Wind POI Supply Curves..... | 5-36 |
| Figure 5-9 | Normalized Monthly Offshore Wind Energy Profile | 5-37 |
| Figure 5-10 | Geothermal POI Supply Curves..... | 5-45 |
| Figure 5-11 | Run-of-river POI Supply Curves..... | 5-54 |
| Figure 5-12 | Normalized Monthly Run-of-river Energy Profiles by Transmission Region | 5-55 |
| Figure 5-13 | Pumped Storage POI Supply Curves..... | 5-58 |
| Figure 5-14 | CCGT and Small Cogeneration POI Supply Curves* | 5-69 |
| Figure 5-15 | Coal-Fired Generation with CCS POI Supply Curve* | 5-72 |
| Figure 5-16 | Wave POI Supply Curves | 5-77 |
| Figure 5-17 | Monthly Energy Profile – Wave Potential..... | 5-78 |
| Figure 5-18 | Tidal POI Supply Curve | 5-82 |
| Figure 5-19 | Monthly Energy Profile – Tidal Potential (Discovery Passage)..... | 5-83 |
| Figure 5-20 | Range of Application of existing Storage Technologies | 5-87 |
| Figure 5-21 | Solar POI Supply Curves | 5-94 |
| Figure 5-22 | Normalized Monthly Solar Energy Profiles by Transmission Region | 5-95 |

Figure 5-23 Supply-Side Generation Resource Potential Supply Curve
Summary – Base UECs \$/MWh at POI..... 5-100

Figure 5-24 Overview of Transmission System and Cut-Planes 5-116

List of Tables

Table 5-1 Exclusion Zones..... 5-5

Table 5-2 Summary of Wood Based Biomass Potential..... 5-13

Table 5-3 Summary of Biogas Potential..... 5-19

Table 5-4 Summary of MSW Potential 5-27

Table 5-5 Summary of Onshore Wind Potential..... 5-31

Table 5-6 Summary of Offshore Wind Potential..... 5-35

Table 5-7 Summary of Geothermal Potential 5-44

Table 5-8 Summary of Run-of-river Potential..... 5-53

Table 5-9 Summary of Pumped Storage Potential..... 5-57

Table 5-10 Site C Summary 5-61

Table 5-11 Summary of Resource Smart Potential..... 5-64

Table 5-12 Summary of CCGT and Small Cogeneration Natural
Gas-Fired Generation Potential 5-67

Table 5-13 Summary of the SCGT Natural Gas Fired Generation
Potential..... 5-68

Table 5-14 Summary of Coal-Fired Generation with CCS Potential 5-71

Table 5-15 Summary of Wave Potential..... 5-76

Table 5-16 Summary of Tidal Potential 5-82

Table 5-17 Summary of Storage Technologies and Applications..... 5-88

Table 5-18 Summary of Solar Potential 5-93

Table 5-19 Inventory of Supply-Side Generation Resource Potential by
Transmission Region 5-99

Table 5-20 Supply-Side Generation Resource Potential – UEC Values
at POI below \$200/MWh..... 5-101

Table 5-21 Summary of Supply-Side Energy Resource Potential by
Resource Type – UEC Values at POI 5-113

Table 5-22 Summary of Supply-Side Capacity Resource Potential –
UCC at POI Summary..... 5-114

Table 5-23 Cut-Plane Capacities 5-117

Table 5-24 Transmission Reinforcement Options Considered in
Long-Term Resource Planning 5-118

Table 5-25 Unit Cost of Power Lines 5-124

| | | |
|------------|---------------------------------------|-------|
| Table 5-26 | Interconnection Substation Cost | 5-124 |
| Table 5-27 | Voltage Transformation Cost | 5-124 |

5.1 Introduction

Supply-side resource options include generation, storage and transmission resources. The following chapter presents an overview of the supply-side resource options and provides the underlying assumptions. The unit energy cost (**UEC**) and unit capacity cost (**UCC**) for the generation resource options in this chapter are presented at the point of interconnection (**POI**).

5.1.1 RODAT & ROMAP Databases

For long-term provincial-level resource planning exercises, potential supply-side data are evaluated in terms of technical, financial, environmental and economic development attributes. The resource options data is captured in the Resource Options Database (**RODAT**) and Resource Options Mapping Database (**ROMAP**):

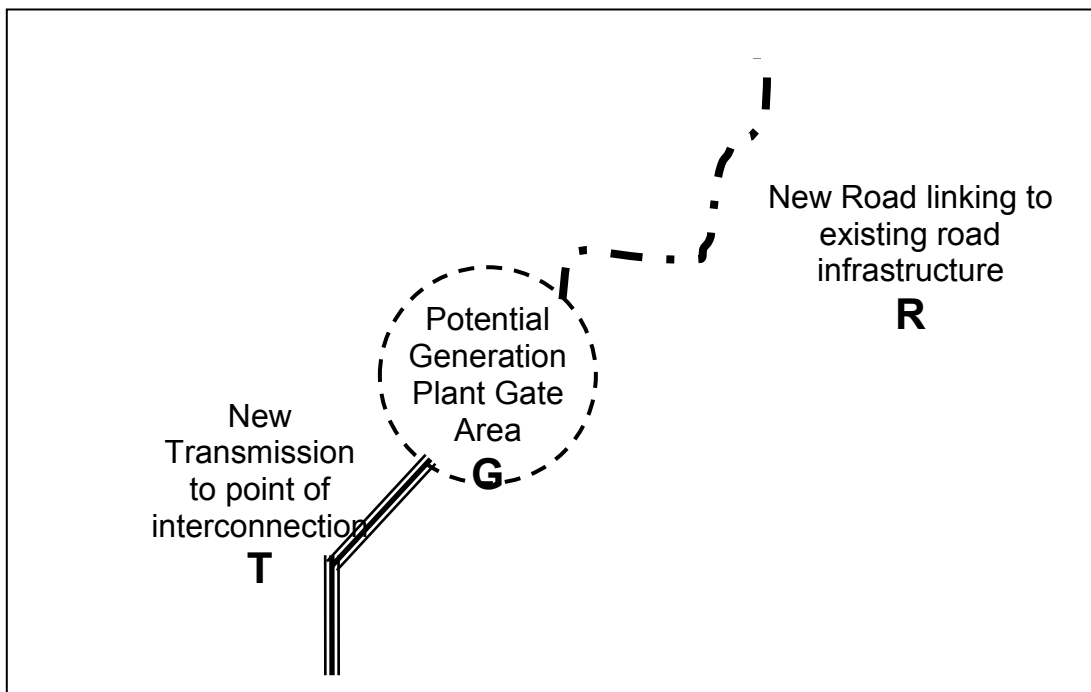
- **RODAT:** Stores technical, financial, environmental and economic development information on the potential resource options and creates summary sheets showing the attributes of each resource options at the project, bundle or cluster levels. The RODAT summary sheets in Appendix 3 present the resource options with UECs less than \$200/MWh or UCCs less than \$125/kW-yr.
- **ROMAP:** Stores potential resource options data in a Geographical Information System (**GIS**) database that allows the mapping of potential resources, including the new access roads and transmission corridors required to link potential sites to existing infrastructure. ROMAP facilitates the identification of clusters of energy or capacity in relation to the existing landscape features (e.g., water bodies, towns), exclusion areas (e.g., parks, conservancies) and infrastructure (e.g., transmission, road networks). Appendix 5 provides more detailed information on ROMAP.

The databases allow the resource options to be summarized in terms of a project, bundles of projects, and clusters of projects:

- 1 • **Project:** A potential project is divided into three components that describe the
2 total resource option at the POI to the electric system. These components are:
3 ▶ **Plant gate (G):** Plant gate area containing supply-side generation works
4 and equipment
5 ▶ **Road (R) corridor:** Road corridor (length and width) linking plant gate area
6 to existing road infrastructure
7 ▶ **Transmission (T) corridor:** Transmission corridor (length and width) linking
8 plant gate area to existing transmission infrastructure

9 The technical, financial, environmental and economic development attributes of each
10 component of the potential resource options (G, R, T) are evaluated and stored in
11 the databases.

12 **Figure 5-1 Components (G, R, T) of the Resource**
13 **Options Evaluated to the POI**



1 In this report, as illustrated in [Figure 5-1](#), the technical, financial, environmental and
2 economic development attributes of each resource option are presented at the POI
3 by summing the plant gate (G), new road (R) and new transmission (T) components
4 of each option (i.e., resource option at POI = G + R + T).

5 Resource potential can be reported in terms of a specific project, a bundle of
6 projects or a cluster of projects. Bundled and clustered information is defined as
7 follows:

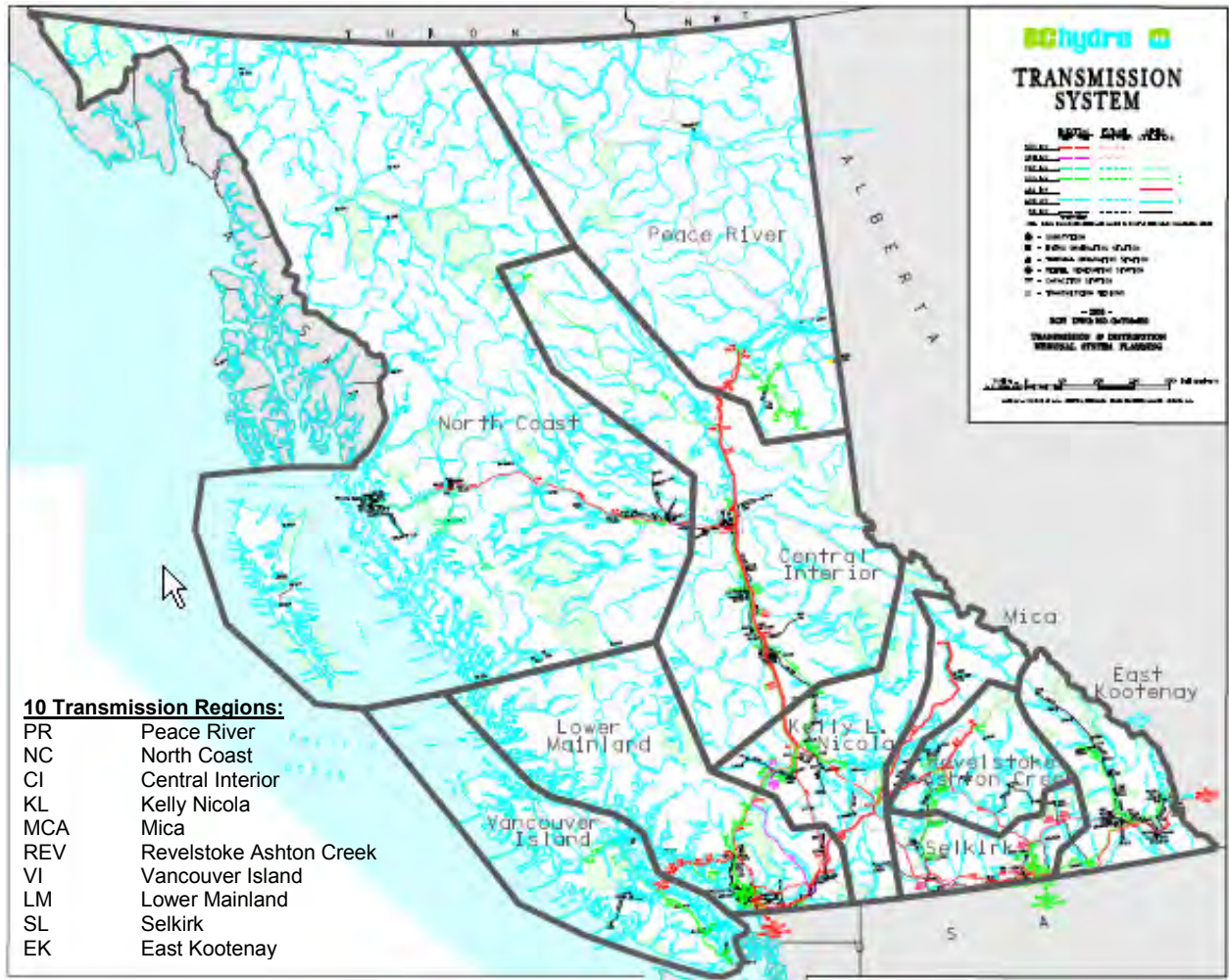
- 8 • **Bundle:** a number of potential projects, of a specific resource type, are bundled
9 and sorted according to a region and cost of energy (\$/MWh). In some cases,
10 for example run-of-river potential having a large number of small projects,
11 resource potential is presented in terms of bundles and bundles are used as
12 input data for resource planning portfolio analysis.
- 13 • **Cluster:** a potential grouping of different generation resource options, within a
14 geographic zone, whose road and transmission components would benefit from
15 economies of scale and shared transmission and road infrastructures. ROMAP
16 stores alternative road and transmission corridors associated with potential
17 projects grouped in clusters. The process of identifying clusters includes
18 mapping resource potential and identifying possible clusters based on energy
19 and capacity densities. The generation resource clusters approach was first
20 introduced in the 2010 Resource Options Report (**ROR**) and considered in the
21 2012 Draft Integrated Resource Plan (**IRP**).

22 This report presents data in the form of points or bundles.

23 Resource options data are reported by transmission region, meaning that though the
24 generation location (G) of a potential resource option is in one transmission region, if
25 the addition of the transmission component (T) interconnects in a different
26 transmission region, the overall project at POI (G + R + T) is reported as being in the

1 zone where interconnection occurs. [Figure 5-2](#) shows a map of the ten transmission
 2 regions used in the 2013 ROR Update.

3 **Figure 5-2 Ten Transmission Planning Regions**



4 **5.1.2 Resource Options Filters**

5 One of the functional elements of the ROMAP GIS database is that it allows screens
 6 to be created to capture areas where resource option development would be
 7 severely constrained or prohibited (e.g., exclusion areas, inaccessible areas such as
 8 glaciers). These screens are used to establish the resource options considered in
 9 the evaluation process by removing potential resource options from consideration.

- 1 Three basic filters remove potential resource options from consideration:
- 2 (i) A potential resource option may not occur within a legally protected area
- 3 (ii) A potential resource option may not occur on a salmon bearing stream
- 4 (iii) A resource option may not occur in a zone identified as being a glacier
- 5 The potential resource options have been screened using the exclusion framework
- 6 summarized in [Table 5-1](#).

7 **Table 5-1 Exclusion Zones**

| Exclusion Zone | Source | Screening Buffer | Screening Criteria ROADS | Screening Criteria POWER LINES | Screening Criteria RESOURCE OPTIONS |
|---|---|--|-------------------------------------|---|--|
| Biodiversity Areas | Province of British Columbia, GeoBC, ILMB | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Wildlife Management Areas Areas for which administration and control was transferred to the Ministry of Environment via the <i>Land Act</i> due to the significance of their wildlife/fish values and designated as Wildlife Management Areas under the <i>Wildlife Act</i> | Province of British Columbia, GeoBC, LRDW | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Conservancy Areas Conservancy areas designated under the <i>Park Act</i> or by the <i>Protected Areas of British Columbia Act</i> , whose management and development is constrained by the <i>Park Act</i> | Province of British Columbia, GeoBC, LRDW | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |

Integrated Resource Plan Appendix 3A-1

| Exclusion Zone | Source | Screening Buffer | Screening Criteria ROADS | Screening Criteria POWER LINES | Screening Criteria RESOURCE OPTIONS |
|--|---|--|---------------------------------|--|--|
| National Parks | Province of British Columbia, GeoBC, LRDW | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Legally Protected Areas Ecological Reserves, Protected Areas, Provincial Parks, Recreation Areas | Province of British Columbia, GeoBC, LRDW | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Canadian Forces Bases | CFB Esquimalt (Navy) CFB Comox (Air Force) | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Migratory Bird Sanctuaries | Environment Canada | No projects within 100 m of exclusion area | None allowed | None allowed | None allowed |
| Marine Wildlife Areas (MWAs)¹ | | Not applicable | Not applicable | Allow MWA designation not yet made: Database tracks resource options which fall within this area | Allow MWA designation not yet made: Database tracks resource options which fall within this area |
| National Marine Conservation Areas No electricity generation is permitted | | No projects within 100 m of exclusion area | Not applicable | None allowed | None allowed |

¹ MWAs are designated by Environment Canada under the *Canada Wildlife Act*. At this time, one site is being considered in British Columbia, the Scott Island Group, located 10 km to 46 km offshore of Cape Scott at the northwestern tip of Vancouver Island. Because of the uncertainty related to the MWA designation in this area, the existing MWA filter “allows” for development in the region and tracks resource options which may fall within the area so that potential resource options can be filtered out, if or, when a designation is made.

| Exclusion Zone | Source | Screening Buffer | Screening Criteria ROADS | Screening Criteria POWER LINES | Screening Criteria RESOURCE OPTIONS |
|--|--|--|---------------------------------|---------------------------------------|--|
| Federal Marine Protected Areas (MPA) 1. Bowie Seamount MPA, 180 km offshore of Gwaii Haanas 2. Endeavour Hydrothermal Vent MPA, 250 km offshore of Vancouver Island. | | No projects within 100 m of exclusion area | Not applicable | None allowed | None allowed |
| Provincial MPAs Provincial Park, Conservancy, <i>Environment and Land Use Act</i> Protected Areas, Recreation Area (128 are marine taken together) and Ecological Reserves (20 marine, called Marine Ecological Reserves - e.g., Race Rocks) | | No projects within 100 m of exclusion area | Not applicable | None allowed | None allowed |
| Other Exclusion Areas Glaciers | Province of British Columbia, GeoBC, CWB | No projects, roads or power lines within 100 m of exclusion area | | | |

1 First Nations may have a desire to provide information on areas that they consider
 2 are inappropriate for development. Should such information be provided, BC Hydro
 3 will convey the information to the government through its consultation reports. At this
 4 time, such information is not being reflected in the 2013 ROR Update exclusion
 5 zones for the following reasons:

- 6 • The 2013 ROR Update is not reviewing individual generation sites,
- 7 • The exclusion areas are presently limited to the areas identified as glaciers and
 8 areas designated through federal or provincial statutes, and
- 9 • The 2013 ROR Update process is not a land use planning exercise.

1 **5.2 Generation Resource Options**

2 **5.2.1 Wood Based Biomass – Standing Timber, Road Side and Sawmill**
 3 **Wood Waste**

4 BC Hydro engaged Industrial Forest Services Ltd. for an update to the 2010
 5 modeling study following the same modeling methodology. In the 2013 Update, the
 6 UECs are calculated at 7 per cent real cost of capital, and are presented in \$2013.

7 **5.2.1.1 Resource Description**

8 Wood based biomass electricity is generated from the combustion or gasification of
 9 organic materials as fuels. For the purpose of the 2013 ROR Update, the following
 10 categories of fuels are considered:

- 11 • **Standing timber** (including Pine Beetle Killed Wood)
- 12 • **Roadside debris** (wood already harvested, but left in the forest or road side,
 13 some are Pine Beetle Killed Wood)
- 14 • **Sawmill wood waste**

15 British Columbia has significant wood based biomass resources. However, there are
 16 many competing uses for these resources. As such, the wood based biomass fuel
 17 potentially available for electricity generation may be significantly less than the total
 18 available resource fuel.

19 The majority of forests in B.C. are owned and managed by the Crown. The quantity
 20 of wood based biomass fuel that is available for electricity generation is determined
 21 (directly or indirectly) by government policies, statutes, regulations and by
 22 economics (i.e., harvesting economics and the economics of other competing
 23 industries). It is the responsibility of the Ministry of Forests, Lands and Natural
 24 Resource Operations to ensure forest sustainability, and to allocate fibre through the
 25 setting of annual allowable cuts (**AAC**) and granting of harvesting tenures/licences.
 26 After the AAC is set and allocated to users, the actual amount harvested and used

1 for various purposes/industries is largely a matter of the economics of supply and
2 demand. These economic factors include:

- 3 • Demand and price for processed wood such as lumber, pulp, paper, wood
4 pellets, plywood, fibre boards, biomass heat and energy
- 5 • The location of wood processing facilities relative to the location of the wood
6 supply influences fibre delivery costs

7 **5.2.1.2 Methodology**

8 For the 2010 ROR, BC Hydro engaged a team of consultants from Industrial Forest
9 Services Ltd., together with industry experts, to conduct a modeling study to
10 estimate the long-term wood based biomass energy potential, costs and possible
11 locations of wood based biomass delivery points. That study was overseen by a
12 working group comprised of representatives from BC Hydro, the Ministry of Forests,
13 Lands and Natural Resource Operations and the Ministry of Energy and Mines.
14 Study approach and results were discussed with stakeholders through the ROR
15 process in 2010. This study was updated in 2013 by Industrial Forest Services Ltd
16 following the same modeling methodology.

17 The modeling study was done primarily using the B.C. Fibre model. This model is a
18 regional fibre forecast and fibre allocation model for B.C. The B.C. Fibre model is
19 well known and accepted in the forest industry. It is used by industrial clients in the
20 B.C. pulp and paper, solid wood and bio-energy sectors to provide strategic
21 guidance. This study modeled B.C. in 13 forestry sub-regions and reported out
22 results for two periods. The first period from year 2013 to 2024 corresponds to the
23 transition and decline in B.C. Interior harvest levels as a result of the Mountain Pine
24 Beetle epidemic. The second period from year 2025 to 2040 represents the
25 subsequent time when a stable mid-term harvest is forecast.

1 Many assumptions were required to complete this study. The guiding principle was
2 to reflect current knowledge or expectation without speculating future policies, or the
3 demands of new biomass consuming industries.

4 This study estimated the electricity generation potential and fibre cost from wood
5 based biomass with the following key inputs:

- 6 • The government determined AAC
- 7 • Changes to the future harvest as a result of the mountain pine beetle epidemic
- 8 • Changes to the grade of logs as a result of economic shelf life of dead pine
- 9 • The existing sawmill industries and its capacity/ability to utilize the AAC
- 10 • The existing residual industry (pulp mills, pellet plants, power plants, board
11 plants) and its capacity to utilize sawmill residues
- 12 • The current and future demand of the existing residual industry for non-sawlog
13 grade logs
- 14 • The current and future demand of the existing residual industry for road-side
15 logging residues
- 16 • The impact on biomass supplies resulting from the development of electricity
17 purchase agreements resulting from the BC Hydro Integrated Power Offer,
18 Bioenergy Phase 1 and Phase 2 Calls for Power, Conifex and Community
19 Based Biomass Call
- 20 • The economic drivers of the forest industry including:
 - 21 ▶ Lumber prices
 - 22 ▶ Pulp selling prices
 - 23 ▶ Paper selling prices
 - 24 ▶ Can\$/US\$ exchange

1 ▶ Housing starts

2 Within each of the 13 forestry sub-regions in B.C., log supply (sawlog and biomass)
3 was identified and quantified over time based on the above considerations. This was
4 compared to the regional demand for sawlogs and pulplogs. The identification of
5 available biomass for energy production was a large accounting exercise that
6 balanced log/biomass supply against log/biomass demand, and what remained in
7 each region became available for electricity generation.

8 Once the electricity potential for different regions was determined, possible fibre
9 delivery locations were then identified for each region. Key considerations included
10 the location of existing sawmills, infrastructure and location of available fibre. The
11 cost of biomass delivered to these locations for the three wood based biomass
12 sources was estimated. Generic greenfield biomass power plants and their
13 associated development costs were assumed and used to estimate the cost of
14 projects. The cost of a project together with the cost of delivered biomass fuel are
15 used to estimate the unit energy cost (\$/MWh) of the resource.

16 **5.2.1.3 Results**

17 A detailed wood based biomass report is included in Appendix 6. Key observations
18 from the study are listed below:

- 19 • The current volume of biomass in the Province (considering all biomass
20 categories in year 2013) that is surplus to existing demand, potentially available
21 for bioenergy production, is about 27 million cubic metres. This is forecasted to
22 decline significantly over the first period and is forecasted to stabilize by 2025 in
23 the second period at about 10 million cubic metres (9.8 TWh equivalent of
24 energy per year). The decline is primarily driven by the decline in the availability
25 of standing timber resulting from reductions to the annual allowable cut as the
26 near term level has been elevated to speed up the consumption of Pine Beetle
27 affected wood. For the purpose of estimate long term energy potential, the

1 results from the second period are considered for long term planning and are
2 summarized in [Table 5-2](#).

- 3 • Compared to the results in the 2010 ROR study, the forecasted overall biomass
4 energy potential in the Province for the second period has decreased from
5 13 TWh to 9.8 TWh. The biggest decrease is the standing timber potential from
6 8.5 TWh to 6.1 TWh. The potential from sawmill wood waste is dropped by
7 about half from 1.3 TWh to 0.7 TWh, and the potential from roadside debris is
8 about the same from 2.8 TWh to 3.0 TWh. The changes are predominately
9 driven by the reduced long term AAC forecasts as well as increased fibre
10 demand resulting from bioenergy projects developed since the 2010 ROR
11 study.
- 12 • There are significant volumes of lower-cost fibre (sawmill woodwaste and
13 roadside woodwaste) potentially available for energy production at
14 approximately 3.7 TWh/year equivalent on a Province-wide basis. Whether the
15 full potential can be realized depends on how closely the economics forecasts
16 of other related industries are to what was modeled, the geographical
17 distribution of the fibre (i.e. whether it is economical to transport to potential
18 power plants), the business strategy plan of the fibre holders and whether the
19 amount of fibre available in any geographical pocket would sustain an
20 economically sized plant.
- 21 • The energy potential from standing timber has added uncertainty compared to
22 the lower-cost fibre in that the business strategy of licence and tenure holders
23 and the additional cost and distance to harvest standing timber all contribute to
24 uncertainty
- 25 • For the purposes of high level long term planning, the potential from
26 woodwaste, roadside debris and pulp log for each region is aggregated as
27 summarized in [Table 5-2](#) and the cost reported reflects the weighted average.
28 The potential and cost for standing timber are reported separately.

1 A summary of the technical and financial results for wood based biomass is
 2 presented in the [Table 5-2](#).

3 **Table 5-2 Summary of Wood Based Biomass**
 4 **Potential**

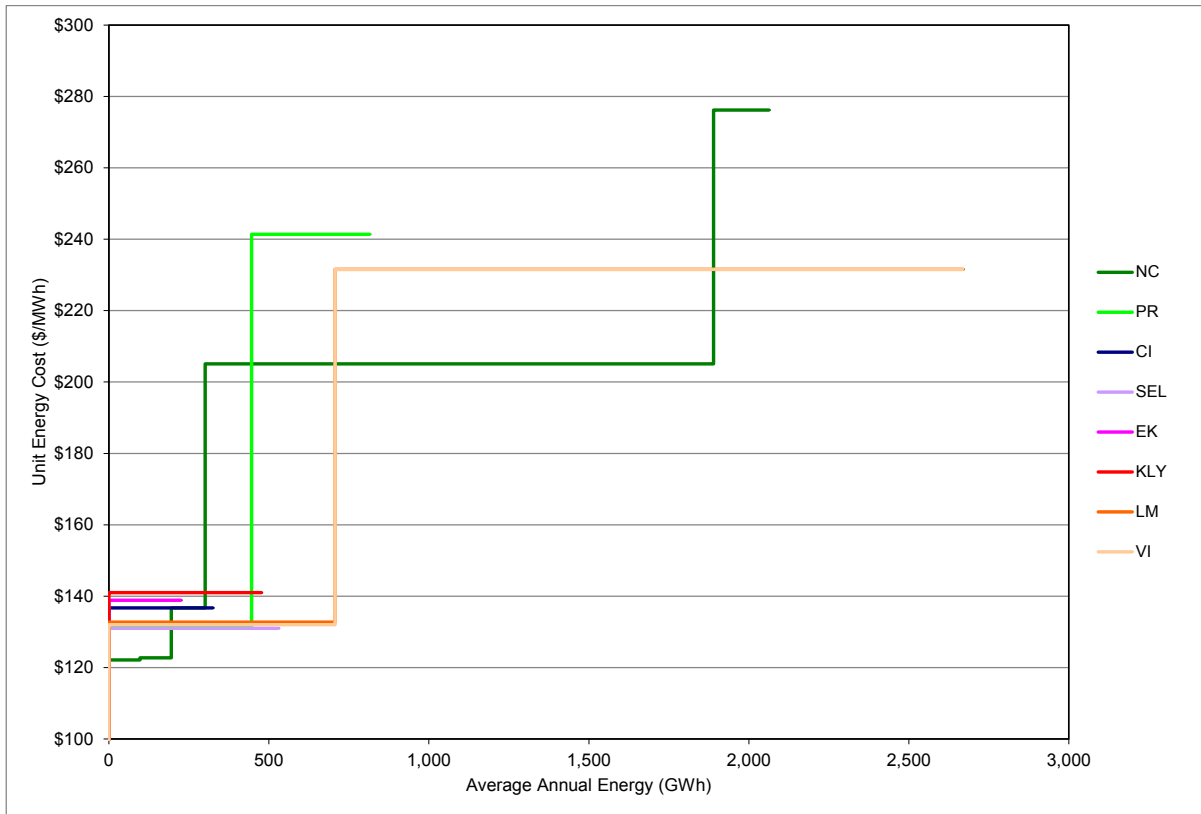
| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|--|--------------------|-------------------------|--------------|------------------------|-----------------------------|-------------------------------|
| Standing Timber | | | | | | |
| Peace River | 1 | 46 | 46 | 368 | 368 | 241 |
| North Coast | 2 | 221 | 221 | 1,762 | 1,762 | 205 - 276 |
| Vancouver Island | 1 | 246 | 246 | 1,962 | 1,962 | 232 |
| Lower Mainland | 1 | 246 | 246 | 1,962 | 1,962 | 232 |
| Sub-Total | 5 | 759 | 759 | 6,054 | 6,054 | 205 - 276 |
| Roadside Debris & Woodwaste | | | | | | |
| Peace River | 1 | 56 | 56 | 446 | 446 | 132 |
| North Coast | 3 | 38 | 38 | 301 | 301 | 122 - 137 |
| Central Interior | 1 | 41 | 41 | 325 | 325 | 137 |
| Kelly Nicola | 1 | 60 | 60 | 476 | 476 | 141 |
| Vancouver Island | 1 | 89 | 89 | 707 | 707 | 132 |
| Lower Mainland | 1 | 89 | 89 | 707 | 707 | 133 |
| Selkirk | 1 | 66 | 66 | 530 | 530 | 131 |
| East Kootenay | 1 | 28 | 28 | 225 | 225 | 139 |
| Sub-Total | 10 | 467 | 467 | 3,718 | 3,718 | 122 - 141 |
| Total | 15 | 1,226 | 1,226 | 9,772 | 9,772 | 122 - 276 |

5 * For wood based biomass, this reflects the number of fiber delivery locations considered in the study.
 6 The MWs shown reflect the total generation that could be produced given the estimated fuel supply
 7 and may be done with multiple plants. In general, there is one fiber delivery location assumed for
 8 each forestry sub region unless the potential is small. The boundary of forestry sub regions and
 9 transmission regions do not align, as such, there can be more than one fiber delivery location within
 10 one transmission region.

11 The wood based biomass potential may be associated with existing industrial areas
 12 (e.g., woodwaste from sawmill sites) or with existing road and transmission
 13 infrastructures. A map showing the provincial distribution of the potential wood
 14 based biomass resource option is shown in Appendix 5.

1 The supply curves for the wood based biomass resource potential based on POI
 2 costs, by transmission region, are shown in [Figure 5-3](#).

3 **Figure 5-3 Wood Based Biomass POI Supply Curves**



4 **5.2.1.4 Environmental and Economic Development Attributes**

5 The environmental attributes of the wood based biomass resources are presented in
 6 Appendix 2 and summarized in Appendix 3.

7 The economic development attributes of the wood based biomass resources are
 8 presented in Appendix 4 and summarized in Appendix 3.

9 **5.2.1.5 Seasonality and Intermittence**

10 Wood based biomass resources are a source of firm energy with insignificant
 11 seasonality and intermittence.

1 **5.2.1.6 *Earliest In-Service Date***

2 General construction period and major capital spending for biomass projects happen
 3 over the course of two years. The earliest in-service date (**ISD**) for wood based
 4 biomass is assumed to be 2015.

5 **5.2.1.7 *Uncertainty***

6 The biggest uncertainty regarding wood based biomass energy potential is long-term
 7 fuel availability.

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|--|----------------|--|--------------------------------------|
| Roadside debris and sawmill Wood waste | Survey | Medium | Medium (-10 per cent / +40 per cent) |
| Standing timber | Survey | High | High (-10 per cent / +60 per cent) |

8 **5.2.2 *Biomass – Biogas (Landfill)***

9 The capital and OMA cost estimates have been increased by about 2 per cent. In
 10 the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are
 11 presented in \$2013.

12 **5.2.2.1 *Resource Description***

13 Landfill gas (**LFG**) is created when organic waste in a municipal solid waste landfill
 14 decomposes under anaerobic conditions. This gas consists of approximately
 15 50 per cent methane (the primary component of natural gas) and 50 per cent carbon
 16 dioxide (**CO₂**), as well as a small amount of other organic compounds.

17 Instead of escaping into the atmosphere, LFG can be captured, converted, and used
 18 as an energy source. Additional benefits of capturing the gas include the reduction of
 19 odours and other hazards associated with LFG emissions. The combustion of LFG
 20 helps prevent methane from migrating into the atmosphere and contributing to global
 21 climate change and local smog. The impact of methane as a greenhouse gas is
 22 about 21 times that of CO₂.

1 LFG energy projects can convert LFG into useful energy forms such as electricity,
2 steam, heat, vehicle fuel, or pipeline quality gas. The most common are:

- 3 • Direct use of medium-grade gas
- 4 • Power generation (medium grade)
- 5 • Upgrade to vehicle fuel or pipeline-quality gas (high-grade)

6 Technologies for producing electricity from LFG include internal combustion engines,
7 gas turbines and microturbines.

- 8 • The **internal combustion engine (ICE)** is the most commonly used conversion
9 technology in LFG applications, being used in more than 70 per cent of all
10 existing LFG electricity projects. This is mainly due to their relatively low cost,
11 high efficiency, and good size match with the gas output of many landfills.
12 Normally, an ICE is suitable for sites where gas quantity can produce between
13 800 kW and 3 MW of electricity.
- 14 • **Gas turbines** are typically used in larger LFG energy projects, where LFG
15 volumes are sufficient to generate a minimum of 3 MW, and typically more than
16 5 MW. This technology is competitive in larger LFG electric generation projects
17 because, unlike most ICE systems, gas turbine systems have significant
18 economies of scale. The cost per kW of generating capacity drops as gas
19 turbine size increases, and the electric generation efficiency generally improves
20 as well.
- 21 • **Microturbine** technologies are suitable when LFG availability is less than
22 300 cubic feet/minute (**cfm**), or when LFG has a low methane content (as little
23 as 35 per cent). Microturbines can be added and removed as available gas
24 quantities change. In general, microturbine projects are more expensive on a
25 dollar-per-kW installed capacity basis than ICE projects.

1 **5.2.2.2 Methodology**

2 *Power Potential*

3 A 2008 report by Golder Associates² provides a thorough study of estimated
4 methane generation, for the period 2012 to 2020, from all operating municipal solid
5 waste (**MSW**) landfill sites under provincial jurisdiction with a disposal rate in 2006
6 greater than 10,000 tonnes/year. The study uses a simple modified first-order kinetic
7 model to calculate methane production, based on three main factors: waste tonnage
8 disposed each year, ultimate methane yield (**Lo**) and a methane generation rate
9 constant (**k**). The methodology used to estimate methane generation for each landfill
10 site is described in detail in the Golder Report.

11 The 2010 ROR only examines landfill sites with flow rates greater than 200 cfm, as
12 landfill sites with low-flow rates are not likely to provide sufficient economic
13 incentives for landfill owners to develop LFG projects.

14 Electricity potential is calculated by multiplying the total LFG heat content (**Btu**) by
15 the heat rate of an electrical generator. Total LFG heat content is obtained by
16 multiplying the heat content per tonne of methane by the average tonnes of methane
17 generated per year. A typical ICE heat rate/efficiency is used to calculate the
18 electricity generation for most of the landfill projects in this study. For landfill sites
19 that have a lower flow rate (less than 300 cfm), a typical microturbine heat
20 rate/efficiency is used.

21 A capacity factor of 0.9 is assumed in converting the MWh of generation potential
22 into MW of capacity potential. The average annual energy takes into consideration
23 the unit availability. Since LFG is considered relatively reliable, the dependable
24 capacity is assumed to be 95 per cent of the installed capacity. Firm energy is

² Inventory of Greenhouse Gas Generation from Landfills in British Columbia, by Golder Associates, 2008. The model was developed as a tool to provide a high-level estimate of LFG generation for inventory purposes and not designed to address differences in site specific landfill waste composition or climatic conditions. More sophisticated LFG generation assessment models may exist that have the potential to produce more precise results based on accurate site specific input data.

1 assumed to be equal to annual average energy based on the assumption of steady
2 fuel supply.

3 **Cost**

4 There is a wide range of variability in the capital cost of the recovery systems due to
5 variations in site locations, Site Configurations and gas production ranges.

6 There are two major components of the cost estimates: 1) the capture and flare
7 system (e.g., wells, blowers, flares) and 2) the electricity equipment (e.g., ICEs/gas
8 turbines/microturbines, and gas treatment systems).

9 **Capture and flare system assumptions:**

- 10 • A typical medium size landfill Site Capture/flare system cost is used to calculate
11 system costs for all projects. The cost is prorated according to LFG flow rate of
12 each landfill site.
- 13 • Those landfill sites with existing capture/flare systems are evaluated in more
14 detail. The capital/Operation and Maintenance (**O&M**) costs of these landfill
15 sites are lower due to existing LFG capture systems and generally results in
16 lower costs than LFG projects without existing capture/flare systems.
- 17 • Capture and flare system costs are based on information from the U.S.
18 Environmental Protection Agency

19 **Electricity equipment assumptions:**

- 20 • A typical ICE cost is used to calculate the capital/O&M cost for most of the
21 projects (e.g., \$2300/kW times the project capacity)
- 22 • A typical microturbine cost is used to calculate the capital/O&M cost for the
23 projects with lower LFG flow rates (e.g., less than 300 cfm)
- 24 • Natural gas turbines are not used or evaluated in this study since the project
25 sizes are likely to be less than 4 MW

1 Main Assumptions:

- 2 • The electrical generation facility size is assumed to be constant
- 3 • Methane heat content is assumed to be 53.4 MMBtu/tonne CH₄
- 4 • ICE heat rate is assumed to be 11.7 MMBtu/MWh
- 5 • LFG recovery rate is assumed to be 75 per cent

6 **5.2.2.3 Technical and Financial Results**

7 A summary of the technical and financial results for biogas is presented in [Table 5-3](#).

8 **Table 5-3 Summary of Biogas Potential**

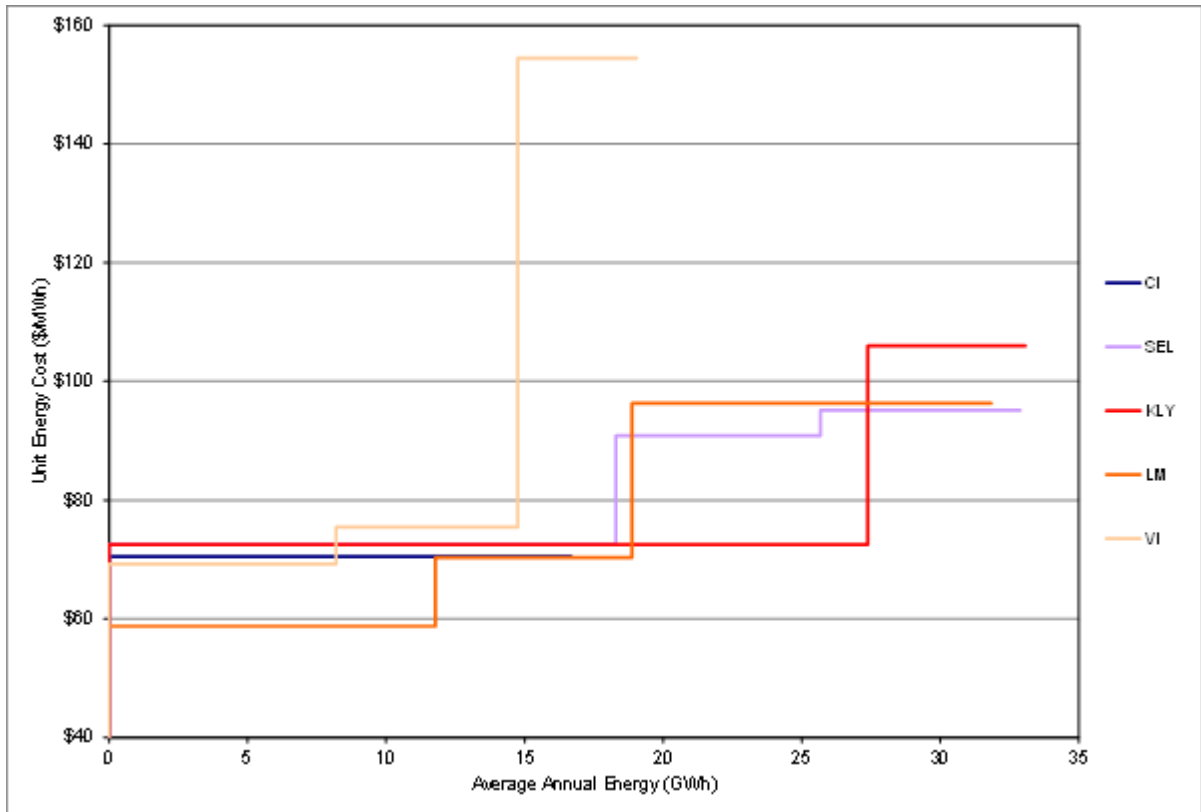
| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|-----------|------------------------|-----------------------------|-------------------------------|
| Central Interior | 1 | 2 | 2 | 17 | 17 | 70 |
| Kelly Nicola | 2 | 4 | 4 | 33 | 33 | 73 - 106 |
| Vancouver Island | 3 | 2 | 2 | 19 | 19 | 69 - 154 |
| Lower Mainland | 3 | 4 | 4 | 32 | 32 | 59 - 96 |
| Selkirk | 3 | 4 | 4 | 33 | 33 | 73 - 95 |
| Total | 12 | 17 | 16 | 134 | 134 | 59 - 154 |

9 A map showing the provincial distribution of the potential biogas resource option is
 10 shown in Appendix 5.

11 The supply curves for biogas resource potential based on POI costs, by
 12 transmission region, are shown in [Figure 5-4](#).

1

Figure 5-4 Biogas POI Supply Curves



2 **5.2.2.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the biogas resources are presented in Appendix 2
 4 and summarized in Appendix 3.

5 The economic development attributes of the biogas resources are presented in
 6 Appendix 4 and summarized in Appendix 3.

7 **5.2.2.5 Earliest In-Service Date**

8 The earliest ISD for biogas is estimated to be 2014.

9 **5.2.2.6 Seasonality and Intermittence**

10 Though there may be variations in biogas release associated with the level of
 11 moisture in the landfill, for planning purposes, biogas resources are considered to be
 12 a source of firm energy with insignificant seasonality and intermittence.

1 **5.2.2.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|-----------------|--|------------------------------------|
| Biogas | Pre-feasibility | Medium | High (-10 per cent / +60 per cent) |

2 **5.2.3 Biomass – Municipal Solid Waste**

3 For the 2013 ROR Update, the cost assumptions have been updated to 2013
 4 numbers, the UECs are calculated at 7 per cent real cost of capital, and the sizing of
 5 the Lower Mainland waste-to-energy (**WTE**) facility has been adjusted to be in line
 6 with the size of WTE facility being studied by Metro Vancouver. Tipping fees for the
 7 various regional districts are based on the latest available estimates. All other inputs
 8 and analysis assumptions are identical to what were used in the 2010 ROR.

9 **5.2.3.1 Resource Description**

10 Biomass - MSW refers to the conversion of MSW into a usable form of energy, such
 11 as heat or electricity. This process is commonly referred to as waste-to-energy. For
 12 the purpose of this ROR, only conversion of waste into electricity is considered. Four
 13 main technologies are available for energy recovery: conventional combustion,
 14 gasification, pyrolysis, and plasma arc gasification. Of these four technologies,
 15 conventional combustion and gasification are the most commonly used MSW
 16 technologies. The following provides a brief description for each of these
 17 technologies.

- 18 • **Conventional combustion:** Mass burn incineration is the most common form
 19 of conventional combustion. Minimal pre-processing of the waste is required for
 20 this process. The MSW is sorted to remove oversized and non-combustible
 21 items as well as hazardous or explosive materials, and then fed into an
 22 incinerator where it is supported on a grate or hearth. Secondary air is added
 23 into the combustion chamber to promote combustion. The resulting bottom ash
 24 is considered non-hazardous, and is deposited at municipal landfills. Fly ash is

1 captured by air pollution control equipment, and usually requires stabilization
2 before it can be deposited in a municipal landfill. Mass burn incineration is
3 considered to be a proven technology, with over 400 plants in Europe,
4 processing approximately 50 million tonnes of waste per year³. A mass burn
5 incineration facility has existed in Burnaby since 2003. This facility processes
6 approximately 280,000 tonnes of MSW per year, and delivers 15 MW of firm
7 capacity. Mass burn facilities can vary in capacity from approximately 36,500 to
8 365,000 tonnes per year. Typical energy recovery efficiencies for mass burn
9 facilities range from 14 per cent to 27 per cent if the recovered energy is being
10 converted into electricity. Higher energy recovery efficiencies are achieved if
11 heat recovery is taken into account.

- 12 • **Standard gasification:** In this process, organic fuel is partially combusted
13 under starved air conditions to generate a synthetic gas, or syngas. The syngas
14 is then cleaned and burned in a second combustion process to produce heat
15 and/or electricity. Standard gasification systems typically require homogenous
16 fuel, and hence extensive pre-processing of the MSW is required which raises
17 costs and requires energy input into the process. Several gasification plants are
18 operating commercially in Japan, with none in Europe or in North America.
19 Gasification plants can range in size from 40,000 to 100,000 tonnes per year⁴.
- 20 • **Pyrolysis:** Pyrolysis is similar to gasification except for the source of heat.
21 Gasification uses the heat from the waste generated inside the reaction
22 chamber whereas pyrolysis uses an external source of heat to drive the
23 process. There are several facilities using pyrolysis in Japan.
- 24 • **Plasma arc gasification:** In this process, waste is transformed into a syngas
25 using extremely high temperatures in an oxygen-starved environment. The high
26 temperatures (from 5,000 to 15,000°C) are due to a thermal plasma field

³ Management of Municipal Solid Waste in Metro Vancouver – A Comparative Analysis of Options for Management of Waste after Recycling, AECOM Canada Ltd., June 2009.

⁴ Waste to Energy: A technical Review of Municipal Solid Waste Thermal Treatment Practices, prepared by Stantec, August 2010.

1 created by directing an electric current through a low pressure gas stream.
2 Plasma arc gasification has attributes similar to standard gasification. An
3 advantage is that the much higher heat destroys all organic contaminants and
4 vitrifies the slag into a reusable aggregate-like substance. The disadvantage is
5 the higher energy requirements to create and maintain the plasma. There are
6 two pilot projects using plasma technology underway in Canada, but there are
7 currently no commercial scale units operational in Europe or North America.

8 **5.2.3.2 Methodology**

9 A generalized methodology is used for the MSW resource option, whereby the
10 potential is estimated based on fuel source availability. In determining the fuel
11 source availability, an attempt was made to incorporate the 'Zero Waste' philosophy
12 which tries to minimize the amount of waste that has to be landfilled through waste
13 avoidance and diversion. Zero Waste has been adopted or is being considered by a
14 number of regional districts. Since WTE facilities require a guaranteed fuel source,
15 potential WTE facilities were sized conservatively so as to not interfere with efforts to
16 implement waste avoidance and diversion strategies.

17 To estimate the fuel source availability for individual regional districts, MSW tonnage
18 numbers were obtained from the 2006 B.C. MSW Tracking Report and extrapolated
19 to 2010 numbers based on population growth rates obtained from B.C. Statistics. In
20 this extrapolation, the disposal (i.e., recycling) rates per capita were assumed to
21 remain at 2006 levels since no significant or consistent trends were evident in the
22 2006 report. For regional districts which did not participate in the 2006 B.C. MSW
23 Tracking Report, data were obtained from regional district waste management plans
24 where available, and again adjusted to 2010 numbers.

25 For each regional district, a 25-year forecast in MSW tonnage was created by using
26 the B.C. Statistics population forecast for each regional district, as well as assuming
27 that the per capita disposal rate would linearly decrease by 6.7 per cent per year
28 between 2010 and 2015. This decrease in disposal rate is similar to what would be

1 required to increase the diversion rate from 55 per cent to 70 per cent over a
 2 five-year period, as planned by Metro Vancouver. The individual MSW tonnage
 3 forecasts were then aggregated for each year to form three larger regional entities
 4 for which the transport of MSW would not exceed 350 km. The three regions that
 5 were considered are:

- 6 • **Vancouver Island**, consisting of the regional districts of Alberni Clayoquot,
 7 Capital, Comox Strathcona, Cowichan Valley, Nanaimo and Powell River.
- 8 • **Lower Mainland**, consisting of the regional districts of Fraser Valley, Metro
 9 Vancouver, Squamish Lillooet and Sunshine Coast.
- 10 • **Okanagan**, consisting of the regional districts of Central Okanagan, North
 11 Okanagan, Okanagan-Similkameen, and Thompson-Nicola.

12 Finally, to ensure a firm fuel source supply and to potentially allow for more
 13 aggressive waste avoidance/reduction strategies, two-thirds of the minimum annual
 14 MSW tonnage forecasted over the 25-year period was used to determine the sizing
 15 of a WTE facility in each of the three regions.

16 Based on the approach described above, the MSW fuel potential for each of the
 17 three regions was estimated as follows:

| Region | MSW (tonne/year) |
|------------------|------------------|
| Vancouver Island | 178,000 |
| Lower Mainland | 772,300 |
| Okanagan | 197,000 |

18 It should be noted that Metro Vancouver has gone through an extensive consultation
 19 and study process and is presently proposing a 370,000 tonne/year WTE facility⁵.

20 The minimum estimated MSW potential for the Lower Mainland (prior to the
 21 one-third reduction) compares well with the forecasted MSW tonnage by Metro

⁵ <http://www.metrovancouver.org/SERVICES/SOLIDWASTE/PLANNING/RECOVER/Pages/Capacity.aspx>

1 Vancouver⁶ (1,158,000 versus 1,125,000). The 370,000 tonne/year WTE facility
2 suggested by Metro Vancouver hence represents a more conservatively sized
3 facility than what the estimated available MSW fuel potential would allow. For
4 consistency, Metro Vancouver's proposal for a 370,000 tonne/year WTE facility for
5 the Lower Mainland was adopted for this analysis.

6 The following assumptions were made:

- 7 • At least 100,000 tonnes of MSW are required to make a WTE facility
8 economically feasible
- 9 • Each facility will use mass burn combustion technology, and will be optimized
10 for electricity generation
- 11 • The analysis does not include utilization of waste heat as this is very location
12 dependent. It is recognized that the exclusion of waste heat utilization results in
13 less cost-effective WTE facilities. The analysis also does not take into account
14 additional electricity savings that would occur due to space heating being offset
15 by waste heat. It is believed, however, that the impacts on DSM savings are of
16 second order.
- 17 • Each WTE facility is assumed to be located in-region
- 18 • Waste composition and energy conversion efficiency are assumed to be the
19 same for each region. A conversion factor of 0.6 MWh/tonne is used for all
20 facilities.
- 21 • Each plant will operate at 100 per cent capacity at all times. Availability is
22 assumed to be 95 per cent (same as Burnaby WTE plant), and 97 per cent is
23 used to determine dependable generating capacity (**DGC**).

⁶ Management of Municipal Solid Waste in Metro Vancouver – A Comparative Analysis of Options for Management of Waste After Recycling, prepared by AECOM Canada Ltd., June 2009.

1 Capital and O&M costs are based on estimates by Ramboll (2007)⁷ which have
 2 been adjusted to January 1, 2013 numbers, and are modelled as functions of WTE
 3 plant size.

| WTE Plant Size (tonne/year) | Capital Cost (\$/tonne) | O&M Cost (\$/tonne) |
|-----------------------------|-------------------------|---------------------|
| 178,000 | 1,165 | 81 |
| 370,000 | 1,034 | 64 |
| 197,000 | 1,148 | 75 |

4 The following tipping fees were assumed for the three regions: \$117/tonne for
 5 Vancouver Island, \$107/tonne for the Lower Mainland, and \$72/tonne for the
 6 Okanagan. These numbers were based on the latest tipping fee estimates available
 7 for the various regional districts. In addition, it was assumed that 2.8 per cent of the
 8 incinerated MSW tonnage would be recovered metal⁸, which then could be sold to
 9 offset the O&M costs. A scrap metal price of \$180/tonne was assumed for this
 10 analysis.

11 **5.2.3.3 Technical and Financial Results**

12 A summary of the technical and financial results for MSW are contained in
 13 [Table 5-4](#).

⁷ Memo to MacViro during the Durham/York Environmental Assessment. Reported in Waste Energy - A Technical Review of Municipal Solid Waste Thermal Treatment Practices – Final Report, prepared by Stantec, August 2010.

⁸ Based on metal recovery from the Burnaby Incinerator. Personal communication with Chris Allan, Senior Engineer, Metro Vancouver - Solid Waste Department.

1

Table 5-4 Summary of MSW Potential

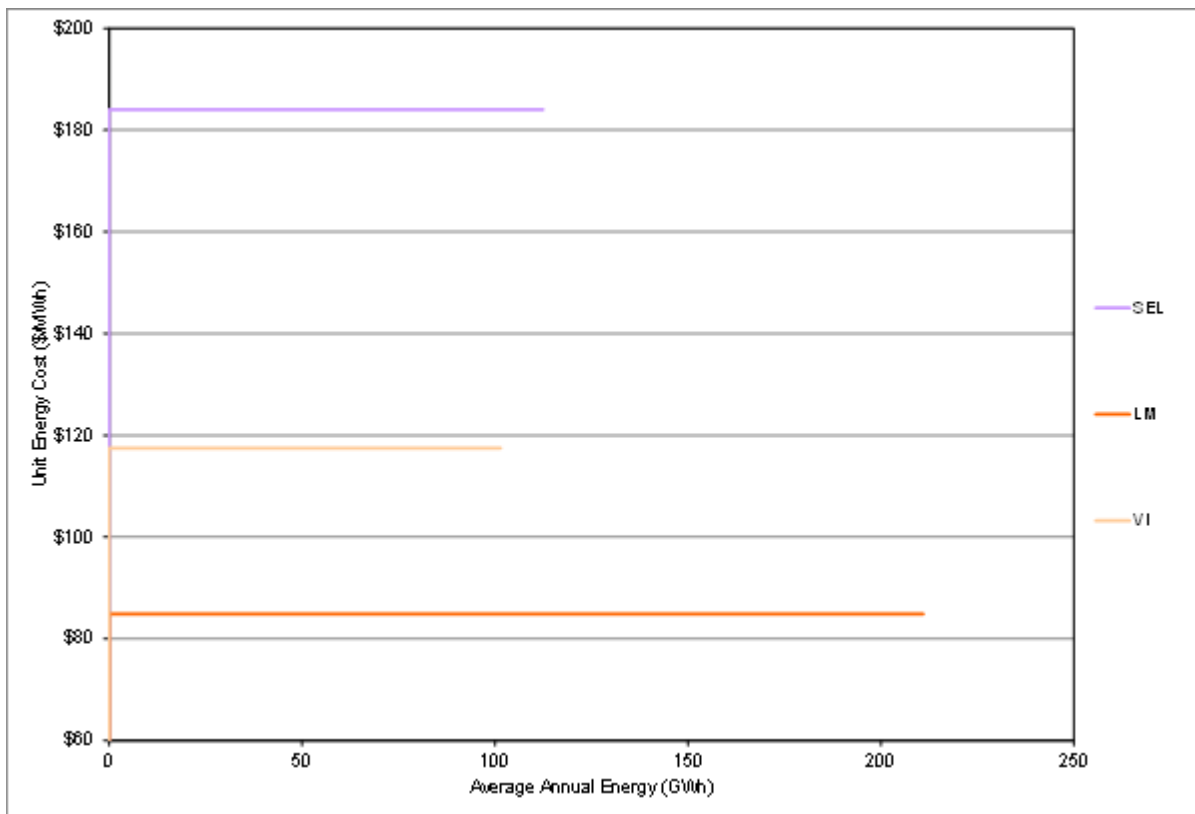
| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|-----------|------------------------|-----------------------------|-------------------------------|
| Vancouver Island | 1 | 12 | 12 | 101 | 101 | 117 |
| Lower Mainland | 1 | 25 | 25 | 211 | 211 | 85 |
| Selkirk | 1 | 14 | 13 | 112 | 112 | 184 |
| Total | 3 | 51 | 50 | 425 | 425 | 85 - 184 |

2 A map showing the provincial distribution of the potential MSW resource option is
 3 shown in Appendix 5.

4 The supply curves for MSW resource potential based on POI costs, by transmission
 5 region, are shown in [Figure 5-5](#).

6

Figure 5-5 Biomass MSW POI Supply Curves



1 **5.2.3.4 Environmental and Economic Development Attributes**

2 The environmental attributes of the biomass MSW resources are presented in
3 Appendix 2 and summarized in Appendix 3.

4 The economic development attributes of the biomass MSW resources are presented
5 in Appendix 4 and summarized in Appendix 3.

6 **5.2.3.5 Earliest In-Service Date**

7 The earliest ISD for biomass MSW is 2018.

8 **5.2.3.6 Seasonality and Intermittence**

9 Biomass MSW resources are a source of firm energy with insignificant seasonality or
10 intermittence.

11 **5.2.3.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------------|-----------------|--|------------------------------------|
| Municipal Solid Waste | Pre-feasibility | Medium | High (-10 per cent / +60 per cent) |

12 **5.2.4 Onshore Wind**

13 The onshore wind resource option has been updated to reflect the most recent
14 trends in turbine efficiencies and pricing. The UECs in the 2013 Update are
15 calculated at 7 per cent real cost of capital, and are presented in \$2013.

16 **5.2.4.1 Resource Description**

17 Wind power refers to the conversion of kinetic energy from moving air into electricity.
18 Modern utility-scale wind turbines are horizontal axis machines with three rotor
19 blades. The blades convert the linear motion of the wind into rotational energy that
20 then is used to drive a generator. Wind generation facilities can be placed on land or
21 on the substrate in water, either in the ocean or possibly in lakes. The onshore and
22 offshore wind assessments are undertaken separately because of the differences in

1 methodologies used to assess the resource potential as well as differences in the
2 financial cost assumptions.

3 **5.2.4.2 Methodology**

4 For the 2010 Resource Options Report, the onshore wind resource potential and
5 costs were based on the following studies:

- 6 • BC Hydro Wind Data Study (DNV Global Energy Concepts Inc., April 2009)
- 7 • BC Hydro Wind Data Study Update (DNV Global Energy Concepts Inc.,
8 September 2009)
- 9 • Updated Capital and O&M Cost Assumptions for Wind Power Development in
10 British Columbia (November 2010, Garrad Hassan) (Appendix 7)

11 These studies were completed as considerable changes in turbine efficiencies and
12 turbine pricing were taking place. Due to an inherent time delay in capturing current
13 data, these changes were not reflected in the studies provided to BC Hydro. The
14 following updates have been made to capture the more recent trends in turbine
15 efficiencies and pricing:

- 16 • **Wind turbine efficiencies:** BC Hydro commissioned DNV-KEMA in May 2012
17 to provide a wind turbine power curve for International Electrotechnical
18 Commission (**IEC**) Class III wind sites (corresponding to low average wind
19 speeds) and to update the power curves for IEC Class I and II wind sites
20 (corresponding to high and medium average wind speeds, respectively). The
21 three wind power curves were developed by blending wind turbine power
22 curves for a number of recent and current turbine models for each of the three
23 IEC classes. The new power curves were then applied to the modelled wind
24 speeds from the original BC Hydro Wind Data Study to create new hourly
25 generation profiles for each wind project. No changes were assumed for turbine
26 hub heights, installed wind capacity of the individual wind projects or wind farm
27 losses. With the application of the revised power curves, the annual net energy

1 production increased on average by 13 per cent for IEC Class I wind projects,
2 6 per cent for IEC Class II wind projects, and 18 per cent for IEC Class III wind
3 projects.

- 4 • **Wind turbine prices:** Over the past decade, wind turbine prices have
5 undergone considerable changes. Turbine prices steadily increased from 2002
6 to 2009. Turbine prices peaked in the first half of 2009, but have dropped since
7 then by approximately 20 to 30 per cent. The trends in turbine prices have been
8 detailed in a number of reports. The increase in turbine prices has been
9 attributed to increased material and labour costs, upscaling of turbine size,
10 decline in the U.S. dollar relative to the Euro, increased costs in turbine
11 warranty provisions, and a general increase in turbine manufacturer profitability
12 due in part to a strong demand growth and turbine and component supply
13 shortages. The decline in wind turbine prices since 2009 has coincided with the
14 downturn in the global economic situation. The reduced turbine demand has
15 increased competition among manufacturers, and shifted the turbine market
16 from a seller's market to a buyer's market. The current wind turbine prices are
17 forecasted to persist through 2015, but it is uncertain if the low sale margins
18 can be maintained by the manufacturers in the long term. Improved efficiencies
19 in the manufacturing process, continued technical advancements, and potential
20 competition from Chinese turbine manufacturers may help keep turbine prices
21 low in the future. At the same time, resurgence in wind turbine demand,
22 resulting in supply chain pressures similar to those observed between 2004 and
23 2009, could counter the cost reductions and increase wind turbine prices. In
24 light of these uncertainties, BC Hydro has decreased the wind turbine price by
25 15 per cent from the original assumption used in the 2010 Resource Options
26 Report.

1 **5.2.4.3 Technical and Financial Results**

2 A summary of the technical and financial results for onshore wind is contained in
 3 [Table 5-5](#).

4 **Table 5-5 Summary of Onshore Wind Potential**

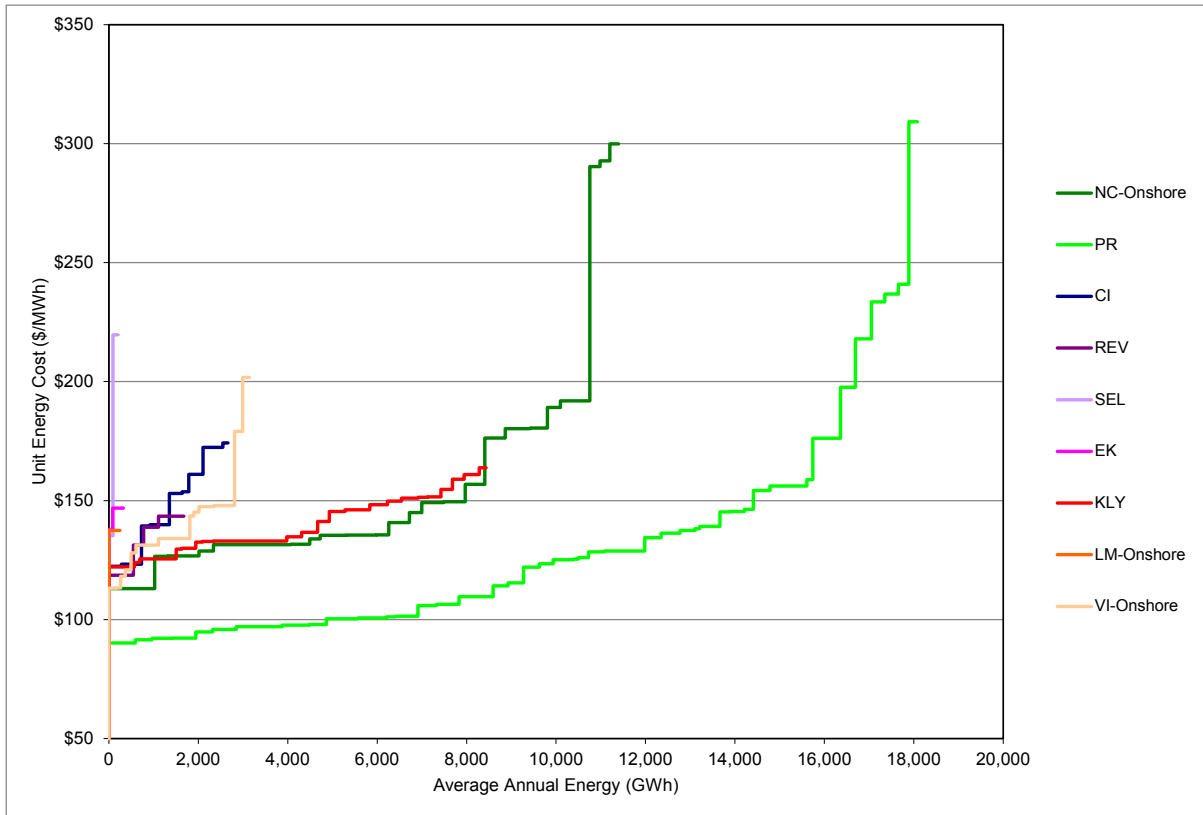
| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|--------------|------------------------|-----------------------------|-------------------------------|
| Peace River | 45 | 5,864 | 1,525 | 18,083 | 18,083 | 90 - 309 |
| North Coast | 23 | 4,085 | 1,062 | 11,400 | 11,400 | 113 - 300 |
| Central Interior | 9 | 1,049 | 273 | 2,660 | 2,660 | 122 - 174 |
| Kelly Nicola | 22 | 3,363 | 874 | 8,437 | 8,437 | 122 - 164 |
| Revelstoke | 4 | 644 | 167 | 1,674 | 1,674 | 119 - 143 |
| Vancouver Island | 13 | 1,111 | 289 | 3,143 | 3,143 | 113 - 202 |
| Lower Mainland | 1 | 90 | 23 | 249 | 249 | 137 |
| Selkirk | 2 | 83 | 22 | 194 | 194 | 135 - 220 |
| East Kootenay | 2 | 138 | 36 | 324 | 324 | 138 - 147 |
| Total | 121 | 16,425 | 4,271 | 46,165 | 46,165 | 90 - 309 |

5 A map showing the provincial distribution of the potential onshore wind resource
 6 option is shown in Appendix 5.

7 The supply curves for onshore wind resource potential based on POI costs, by
 8 transmission region, are shown in [Figure 5-6](#).

1

Figure 5-6 Onshore Wind POI Supply Curves



2 **5.2.4.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the onshore wind resource are presented in
 4 Appendix 2 and summarized in Appendix 3.

5 The economic development attributes of the onshore wind resources are presented
 6 in Appendix 4 and summarized in Appendix 3.

7 **5.2.4.5 Earliest In-Service Date**

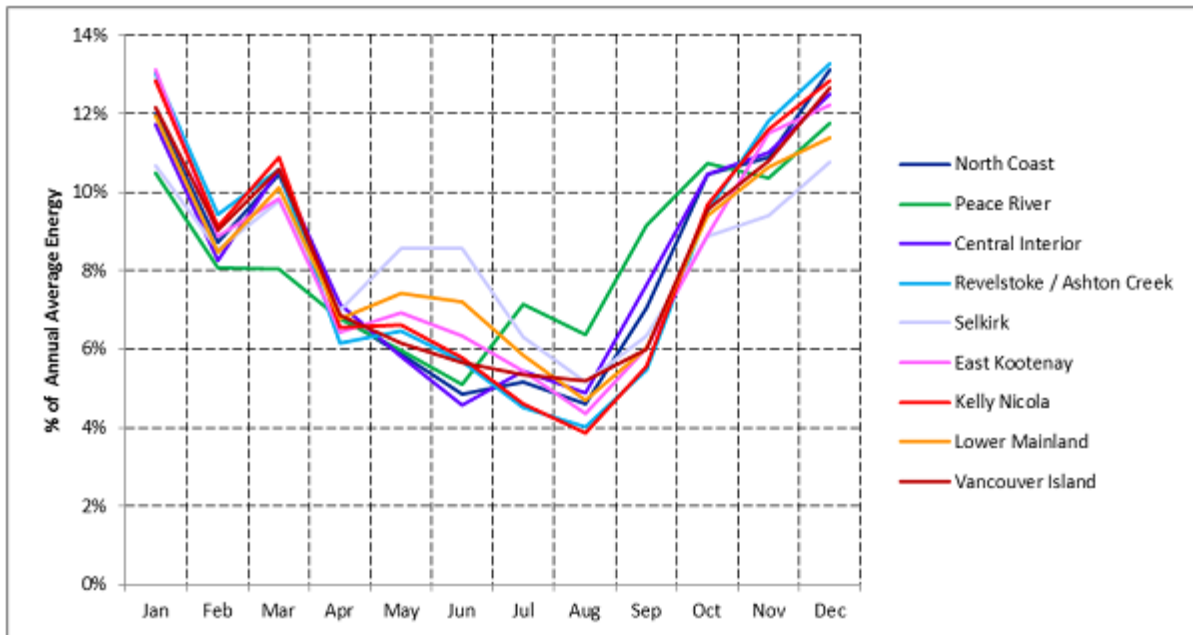
8 The earliest ISD for additional onshore wind generation is 2018.

9 **5.2.4.6 Seasonality and Intermittence**

10 The seasonality of onshore wind resources is shown in [Figure 5-7](#) for each of the
 11 transmission regions. Onshore wind is considered to be an intermittent resource.

1
2

Figure 5-7 Normalized Monthly Onshore Wind Energy Profiles by Transmission Region



3 **5.2.4.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|-----------------|--|--------------------------------------|
| Onshore Wind | Pre-feasibility | Low | Medium (-10 per cent / +40 per cent) |

4 **5.2.5 Offshore Wind**

5 For this ROR, the turbine nameplate capacity for the offshore wind resource option
 6 has been increased to reflect the current global trend in offshore wind turbine sizing,
 7 as well as an updated power curve has been applied to estimate the annual energy
 8 production. In the 2013 Update, UECs are calculated at 7 per cent real cost of
 9 capital; all other cost assumptions are identical to what were used in the 2010 ROR,
 10 and cost estimates are presented in \$2013.

11 **5.2.5.1 Resource Description**

12 The following section evaluates the potential to generate electricity with offshore
 13 wind turbines located in ocean substrate depths of up to 40 m.

1 **5.2.5.2 Methodology**

2 The analysis is based on averaged wind speeds at 80 m hub height from the
3 Canadian Wind Atlas, and gridded bathymetric data provided by the Canadian
4 Hydrological Services. Modelled wind speeds from the Canadian Wind Atlas were
5 compared to long-term wind speed estimates based on actual offshore observations.
6 As a result of this comparison, the modelled wind speeds of the Canadian Wind
7 Atlas were adjusted upward by 0.6 m/s.

8 To identify potential project locations, the following criteria were used:

- 9 • 80-m wind speeds ≥ 8 m/s
- 10 • Water depth ≤ 40 m
- 11 • Area size of project ≥ 14.5 km². This equates to a minimum project size of
12 83.5 MW, based on a turbine nameplate capacity of 3.6 MW, and a turbine
13 density of 1.6 turbines/km²

14 A GIS analysis was performed to delineate the potential project areas, and for each
15 project, the percentage of area for three water depth intervals (0 m to 20 m,
16 20 m to 30 m, and 30 m to 40 m) was determined. In the delineation process, the
17 maximum project area size was limited to 83 km² (or 478 MW), and projects greater
18 than 83 km² were split into smaller projects. In addition, a buffer zone of 14 km along
19 the dominant wind direction and 5 km perpendicular to the dominant wind direction
20 was implemented. Screens for legally protected areas were applied as described in
21 [Table 5-1](#).

22 To estimate the installed capacity and the annual energy production, the following
23 assumptions were made:

- 24 • Turbine density of 1.6 turbines/km²
- 25 • Generic IEC Class I turbine with a nameplate capacity of 3.6 MW

- 1 • Power curve for a generic IEC Class I turbine, assuming an air density of
- 2 1.25 kg/m³
- 3 • Total (excluding transmission) loss factor of 18.5 per cent
- 4 • Weibull distribution with a shape factor of 2.0

5 The average annual energy was determined using the same methodology as applied
 6 in the BC Hydro Wind Data Study Update. Representative costs for offshore wind
 7 projects as a function of water depth were provided by Garrad Hassan (Appendix 7),
 8 and water depth was taken into account in the UEC calculations. It should be noted
 9 that the cost estimates provided by Garrad Hassan assume a certain level of
 10 constructability. Factors such as seabed substrate or wave heights, which can have
 11 impacts on costs, have not been considered.

12 **5.2.5.3 Technical and Financial Results**

13 A summary of the technical and financial results for offshore wind are contained in
 14 [Table 5-6](#).

15 **Table 5-6 Summary of Offshore Wind Potential**

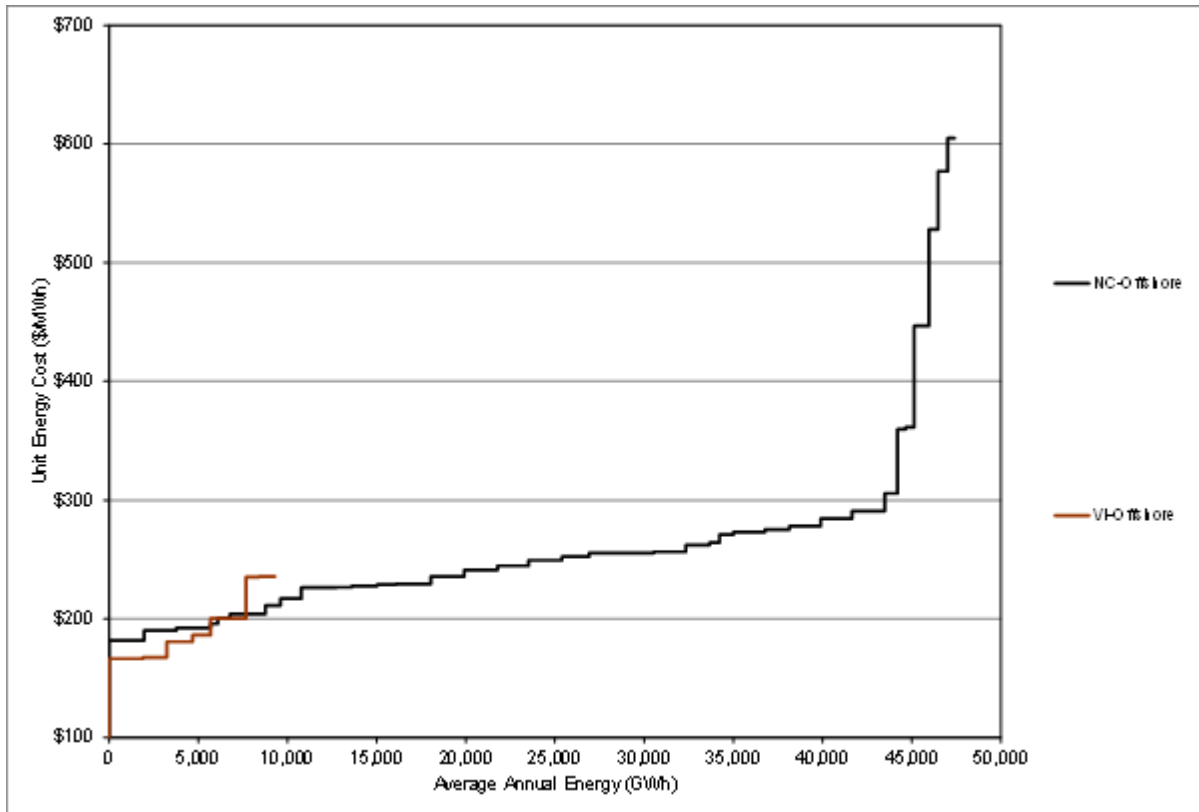
| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|--------------|------------------------|-----------------------------|-------------------------------|
| North Coast | 36 | 12,319 | 3,203 | 47,397 | 47,397 | 182 - 605 |
| Vancouver Island | 7 | 2,369 | 616 | 9,303 | 9,303 | 166 - 236 |
| Total | 43 | 14,688 | 3,819 | 56,700 | 56,700 | 166 - 605 |

16 A map showing the provincial distribution of the potential offshore wind resource
 17 option is shown in Appendix 5.

18 The supply curves for offshore wind resource potential based on POI costs, by
 19 transmission region, are shown in [Figure 5-8](#).

1

Figure 5-8 Offshore Wind POI Supply Curves



2 **5.2.5.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the offshore wind resources are presented in
 4 Appendix 2 and summarized in Appendix 3.

5 The economic development attributes of the offshore wind resources are presented
 6 in Appendix 4 and summarized in Appendix 3.

7 **5.2.5.5 Earliest In-Service Date**

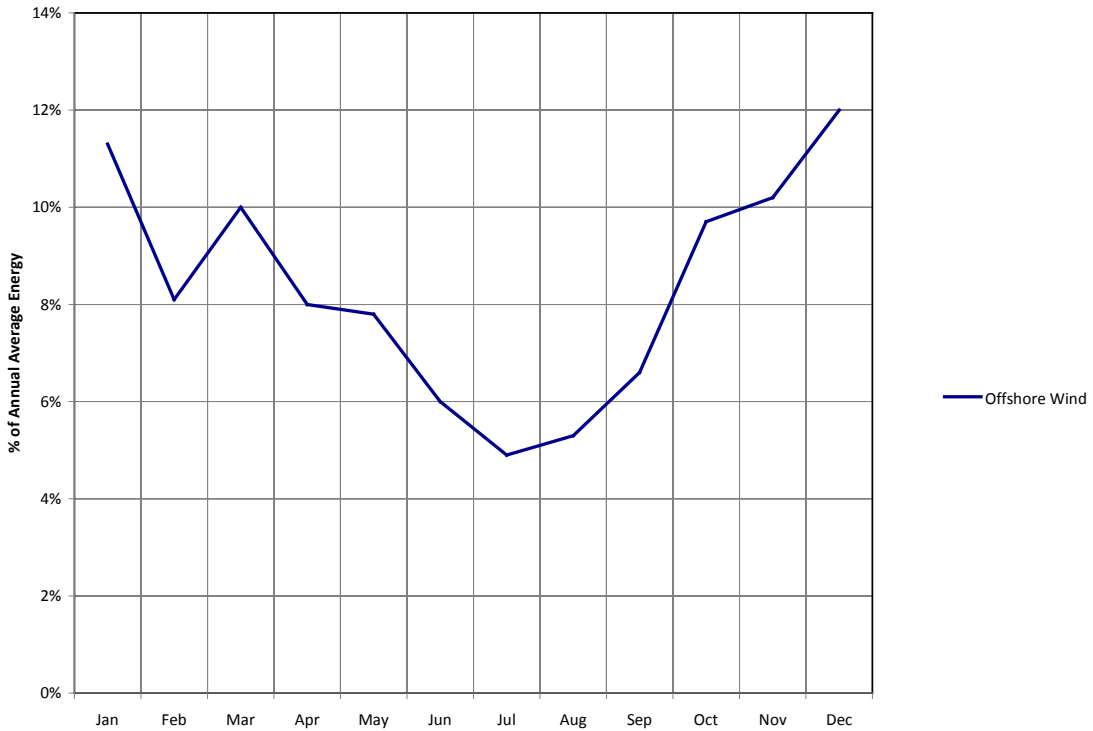
8 The earliest ISD for additional offshore wind generation is 2019.

9 **5.2.5.6 Seasonality and Intermittence**

10 As presented in [Figure 5-9](#), the offshore wind generation potential is assumed to
 11 possess the same seasonal characteristics as the offshore project modelled in the

1 BC Hydro Wind Data Study. Offshore wind is considered to be an intermittent
 2 resource.

3 **Figure 5-9 Normalized Monthly Offshore Wind**
 4 **Energy Profile**



5 **5.2.5.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|-----------------|--|------------------------------------|
| Offshore Wind | Pre-feasibility | Medium | High (-10 per cent / +60 per cent) |

6 **5.2.6 Geothermal Potential**

7 The cost parameters used in the 2010 ROR are adjusted to account for the
 8 challenging geographical conditions of B.C. sites and the higher risk of failed wells
 9 for B.C. greenfield sites. In the 2013 Update, the UECs are calculated at 7 per cent
 10 real cost of capital, and are presented in \$2013.

1 The cost estimates presented in the 2010 ROR were based on the GeothermEx
2 assessment. For the 2013 ROR Update, BC Hydro reviewed a number of external
3 studies to develop its cost assessment. Cost parameters were first assigned based
4 on a high-level review of published costs for new geothermal projects globally, and
5 then adjusted to account for: 1) the challenging geographical conditions of B.C. sites
6 (i.e., higher equipment deployment costs due to the remoteness and difficult terrain);
7 and 2) the higher risk of failed wells for B.C. greenfield sites relative to expansion
8 projects of well-understood geothermal reservoirs (i.e., higher drilling costs due to
9 B.C.'s resources not being previously characterized through exploration and
10 development). It should be noted that even with these adjustments, given the high
11 risks and challenges associated with the three stages of the development of
12 geothermal resources – and in particular production and re-injection drilling – the
13 estimates shown may not actually result in operational facilities.

14 **5.2.6.1 Resource Description**

15 Geothermal energy systems draw on natural heat from within the Earth's crust to
16 drive conventional power generation technologies. The primary source of
17 geothermal energy is radioactive decay occurring deep within the Earth,
18 supplemented by residual heat from the Earth's formation and heat generated by the
19 Earth's gravitational forces pulling dense materials into the Earth's core.

20 The majority of existing geothermal power plants draw energy from reservoirs of
21 gaseous or liquid water in permeable rock located at depths of up to 3,500 m. These
22 hydrothermal reservoirs, which are subdivided into vapour and liquid-dominated
23 resources depending on whether primarily steam or liquid water is present, are the
24 result of heat transfer to local aquifers from geologically active high-temperature
25 belts located relatively close to the Earth's surface. To date, most geothermal plants
26 have been sited in areas with high subsurface temperatures, high rock permeability,
27 and a naturally occurring water-steam resource.

1 For electric power production from new conventional hydrothermal resources,
2 geothermal reservoirs are tapped by drilling production wells, typically greater than
3 15 cm in diameter and up to 6,500 m in depth. Several production wells spaced
4 200 m to 500 m apart, each having net capacities of 2 MW to 10 MW, are connected
5 by steam lines to a central power plant. Condensate from the power plants is
6 distributed to injection wells, returning the fluid volume to the underground reservoir.
7 Existing conventional hydrothermal operations that supply electrical power in the
8 western United States typically vary in size from 10 MW to 260 MW.

9 For reservoirs filled with naturally occurring pressurized dry steam, a simple
10 direct-steam power plant consists of pipes directly connecting the production wells to
11 a turbine to generate electricity. Turbine exhaust is usually run through a condenser,
12 turning the steam into liquid that is returned to the reservoir in injection wells. No dry
13 steam resources have been found in Canada, and are thought to be rare outside of
14 the geyser formations in the southern U.S.

15 For high-temperature (above 180°C) fluid-dominated reservoirs, a flash-steam power
16 plant uses an intermediary vessel to vaporize a portion of the reservoir fluid drawn
17 up from the production well before it is dried and passed through a conventional
18 steam turbine at the power house. The un-vaporized liquid, also known as brine, is
19 combined with the condensate from the turbine and re-injected into the reservoir.
20 Some flash plants can repeat the vaporizing stage and introduce steam into a low
21 pressure turbine in order to extract more energy before it is returned to the reservoir.

22 For moderate temperature systems (120°C to 170°C), binary-cycle power plants are
23 used, whereby the geothermal fluid produced is put through a heat exchanger in
24 which a secondary working fluid with a low boiling temperature, such as iso-butane,
25 benzene or propane, is vaporized. The gaseous working fluid is passed through a
26 specially designed turbine to generate electricity, liquefied in a condenser, and
27 returned to the heat exchanger to again vaporize when heated by new geothermal

1 fluids. Spent geothermal fluid is commonly returned into reservoir through injection
2 wells.

3 Beyond conventional hydrothermal resources, three other types of geothermal
4 resources are often considered suitable for power generation. Co-produced fluids
5 refer to the hot water that accompanies oil and gas produced from deep wells in
6 hydrocarbon fields. Collecting and passing the hot fluid through a binary-cycle power
7 plant may be relatively inexpensive by piggybacking on existing infrastructure and
8 eliminating the need for new drilling. The oil and gas development in Northeast B.C.
9 has resulted in many deep but relatively slim wells, as well as some data on the
10 temperature and flow of geothermal fluids. The potential for co-produced fluids or
11 binary geothermal generation in Northeast B.C. is being currently assessed.

12 Co-produced fluids will not be considered in the 2013 ROR Update pending
13 completion of the Northeast B.C. resource assessment. Also accompanying some oil
14 and gas operations in sedimentary basins are geo-pressured fluids composed of hot
15 pressurized brine containing dissolved methane. The heat and the pressure in the
16 fluids can be used to drive electrical generation equipment, while piggybacking on
17 the existing oil and gas infrastructure to make development of geo-pressured
18 resources cost-effective. The presence of geo-pressured fluid resources is unknown
19 in B.C., and hence it is not considered at this time.

20 Finally, Hot Dry Rock (**HDR**) resources are found in areas offering sufficient heat for
21 power generation but lacking an in situ water-steam supply and/or permeability of
22 the geology. HDR is the most abundant and widely distributed geothermal resource,
23 but bringing to the surface the heat energy locked in rock formations up to 10 km
24 deep involves subsurface fracturing of impermeable rock, followed by the pumping
25 of surface water or groundwater into the fractured area to create an artificial
26 reservoir. Once the artificial reservoir has been proven sufficiently porous to allow
27 water to permeate the rock structure and to absorb heat, and at the same time to
28 retain a sufficient volume of heated water without it dissipating into the earth,
29 pumped surface or ground water can then be delivered to a binary-cycle power plant

1 via a production well. The Enhanced Geothermal Systems (**EGS**) required to tapping
2 into HDR resources are currently in the early phases of development. Due to the
3 largely speculative timeline for the technical viability of HDR-based systems, they
4 were not considered in this report.

5 For reasons stated above, only conventional hydrothermal resources using flash or
6 binary technologies are considered within the scope for the assessment in the
7 2013 ROR Update. Nonetheless, it bears mentioning that there may be potentially
8 significant co-produced fluid and HDR resources in B.C. that could increase the
9 potential geothermal resource base of British Columbia.

10 **5.2.6.2 Methodology**

11 There have been historical efforts to collect data on the hydrothermal resource
12 potential in B.C. – notably at Mount Meager by the National Geothermal Energy
13 Program and subsequent private developers. The Geological Survey of Canada
14 published the Geothermal Energy Resource Potential of Canada in 2011 to
15 summarize data collection and analysis from the 48 years of geothermal research
16 led by the National Geothermal Energy Program. The primary conclusion of the
17 report states: “Canada’s in-place geothermal power exceeds one million times
18 Canada’s current electrical consumption. However, only a fraction of this total
19 potential could be developed.”

20 B.C.’s geothermal potential is illustrated in the map “Geothermal Resources of
21 British Columbia” (Fairbank and Faulkner 1992) that integrates the known elements
22 of the B.C. resource. The map indicates 18 general areas of low, moderate and high
23 temperature geothermal potential throughout the province. These areas include the
24 Garibaldi Volcanic Belt, Pemberton Belt, Harrison Lake area, Okanagan Valley, Low
25 Arrow Lake area, Kootenay Lake area, Southern Rocky Mountain Trench, Upper
26 Arrow Lake area, Valemount area, Hudson’s Hope area, Northeast British Columbia
27 Thermal Anomaly, Liard River area, the Stikine Volcanic Belt, Mount Edziza area,
28 Lakelse Lake, Gardener Canal area, King Island area and the Anahim Volcanic Belt.

1 A summary of the research to date is articulated in the Geothermal Potential of the
2 Cordillera (Jessop 2008): “The geothermal resource base is very large, but the
3 difference between the resource base and the usable resource is also very large.”

4 The electric power generation potential from a usable resource depends on the
5 thermal energy present in the reservoir, the amount of thermal energy that can be
6 extracted from the reservoir at the wellhead, and the efficiency with which that
7 wellhead thermal energy can be converted to electric power. The challenge in the
8 resource assessment lies in quantifying the size and thermal energy of a reservoir
9 as well as the constraints on extracting that thermal energy. In B.C., there has been
10 relatively little targeted geothermal exploration to confirm the thermal properties of
11 geothermal reservoirs or understand the constraints on bringing hot fluid from the
12 reservoir to the surface.

13 Estimates of the near-term geothermal generation potential in B.C. have been
14 conducted by GeothermEx, a U.S. based geothermal consultancy, as part of the
15 Western Renewable Energy Zones (**WREZ**) project. As per the WREZ report:

16 The methodology used to estimate the geothermal generation
17 potential has relied on volumetric estimation of heat in place
18 wherever sufficient information was available to justify this
19 approach. In brief, the heat-in-place approach entails estimation
20 of the area, thickness, and average temperature of the
21 geothermal resource. Recovery factors that are based on
22 industry experience are applied to estimate the proportion of
23 heat that can be recovered as electrical energy over an
24 assumed project life of 30 years. Uncertainty in the input
25 parameters is handled by a probabilistic approach that yields a
26 range of possible generation values and associated
27 probabilities. The modal value of the probability distribution is
28 considered the “most likely value” of generation potential for the
29 project concerned.

30 Where there is insufficient resource information to apply the
31 heat-in-place method, estimates of generation potential have
32 been made by analogy to better-known projects in similar
33 geologic environments. If the only public information about a
34 project is that it contains geothermal leases or has been the

1 subject of a geological reconnaissance study, the project size
2 has been estimated at a minimum size of 10 MW (gross). Larger
3 estimates of capacity can be justified even in the absence of
4 published resource data if there is evidence of active
5 geothermal development efforts. (For) British Columbia,
6 capacities of 50 MW (gross) have been estimated (for some
7 sites) based on potentially favourable geologic conditions, even
8 in the absence of current development efforts.

9 The GeothermEx assessment identified 18 discrete project locations and assigned
10 an electricity generation potential as per the above methodology. High quality
11 resources were assumed to be developed with flash-steam power plants, whereas
12 medium quality resources were assumed to be developed by binary-cycle power
13 plants. Cost parameters were assigned to these technology types based on a high
14 level review of published costs for new geothermal projects globally, adjusted to
15 account for the challenging geographical conditions of B.C. sites and the higher risk
16 of failed wells for B.C. greenfield sites relative to expansion projects of
17 well-understood geothermal reservoirs.

18 The WREZ methodology is a conservative estimate for B.C. because it includes only
19 the 'discovered' resources and does not include more speculative "undiscovered"
20 resources for which insufficient heat or flow data are currently available.

21 **5.2.6.3 Technical and Financial Results**

22 A summary of the technical and financial results for the geothermal resource option
23 is contained in [Table 5-7](#).

1

Table 5-7 Summary of Geothermal Potential

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/yr) | Annual Firm Energy (GWh/yr) | UEC at POI Range (\$2013/MWh) |
|----------------------------|---------------------------|--------------------------------|-----------------|-------------------------------|------------------------------------|--------------------------------------|
| Peace River | 1 | 20 | 20 | 140 | 140 | 134 |
| North Coast | 3 | 270 | 270 | 2,111 | 2,111 | 97 - 136 |
| Kelly Nicola | 1 | 20 | 20 | 140 | 140 | 141 |
| Revelstoke | 1 | 20 | 20 | 140 | 140 | 142 |
| Vancouver Island | 2 | 70 | 70 | 534 | 534 | 134 - 573 |
| Lower Mainland | 5 | 320 | 320 | 2,505 | 2,505 | 91 - 139 |
| Selkirk | 3 | 60 | 60 | 420 | 420 | 134 - 179 |
| Total | 16 | 780 | 780 | 5,992 | 5,992 | 91 - 573 |

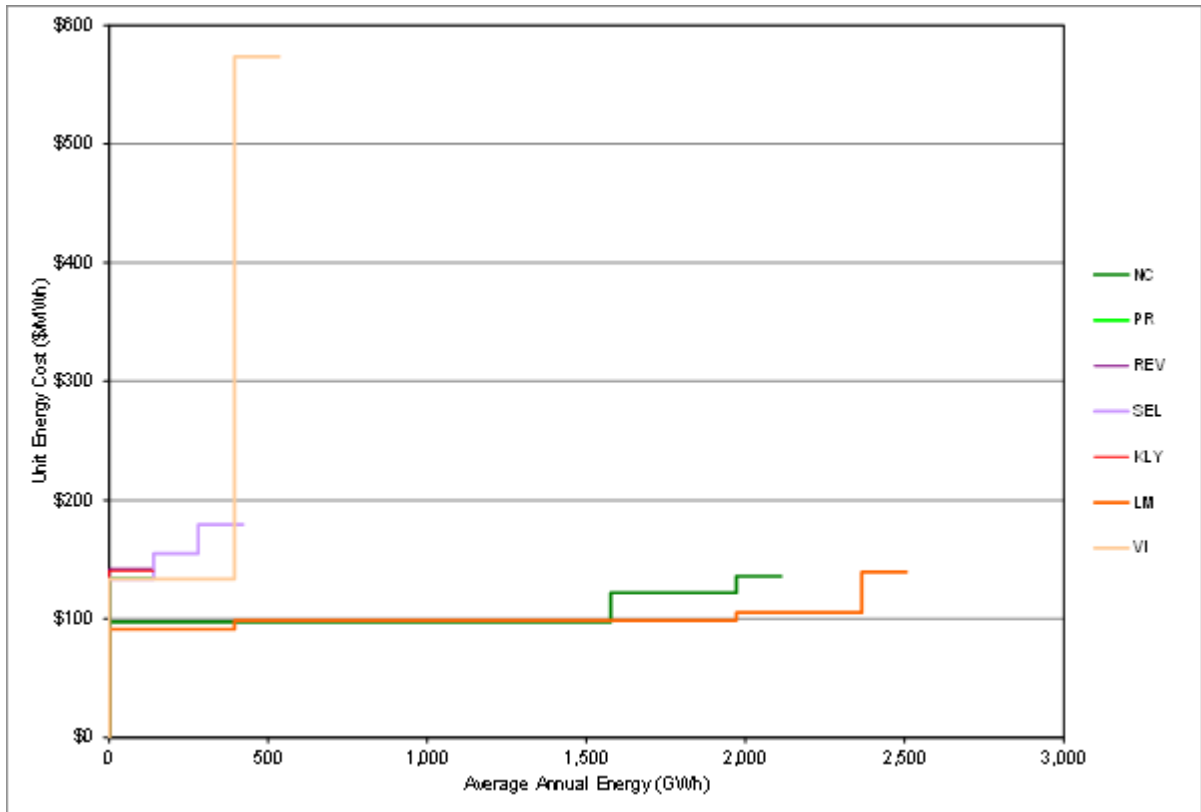
2 Note: Summary table excludes two sites that are technically inaccessible (e.g., within a protected area, or
 3 exceeds technical criteria established for road or transmission access).

4 A map showing the provincial distribution of the potential resource option is shown in
 5 Appendix 5.

6 The supply curves for geothermal resource potential based on POI costs, by
 7 transmission region, are shown in [Figure 5-10](#).

1

Figure 5-10 Geothermal POI Supply Curves



2 **5.2.6.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the geothermal resources are presented in
 4 Appendix 2 and summarized in Appendix 3.

5 The economic development attributes of the geothermal resources are presented in
 6 Appendix 4 and summarized in Appendix 3.

7 **5.2.6.5 Earliest In-Service Date**

8 The earliest ISD for geothermal is estimated to be 2017 for sites that have had
 9 significant previous investigation efforts. For other sites, the earliest ISD is assumed
 10 to be 2019.

1 **5.2.6.6 Seasonality and Intermittence**

2 For resource planning purposes, geothermal resources are considered to be a
3 source of firm energy without significant seasonality or intermittence.

4 **5.2.6.7 Uncertainty**

5 There are risks associated with the confirmation of potential and development of
6 geothermal resources. The development of geothermal resources proceeds in three
7 stages, and at each stage there are risks and challenges to overcome. In the
8 confirmation stage, a potential geothermal reservoir is surveyed and mapped
9 through geological survey techniques and slim-hole drilling. If the results of the
10 confirmation stage are encouraging, the project can proceed to the drilling or
11 feasibility study stage, in which deep production wells are drilled to establish the
12 parameters of the geothermal reservoir, identify the sustainable flow rates from the
13 reservoir, and estimate the financial feasibility of the project. If the drilling or
14 feasibility stage establishes a financial foundation for the project, the construction
15 stage can begin. In the final construction stage, the surface collection systems,
16 generation equipment and interconnection facilities are built. The challenges that
17 must be overcome in each stage in the B.C. context are:

- 18 • Confirmation stage:
- 19 ▶ Proponent must secure tenure to the land and acquire necessary permits for
20 early stage reconnaissance. In B.C., the tenure process requires applicants
21 to request a parcel of land be put up for tenure and must win the rights
22 through a sealed bid auction. The uncertainty related to the auction process
23 is a disincentive for some geothermal developers to invest efforts to
24 investigate new potential sites. Since 2002, the Province has awarded
25 geothermal permits to 12 locations and there is only one active geothermal
26 lease at South Meager Creek.
- 27 ▶ Drilling of three to ten slim-holes may cost from \$0.5 million to \$5 million,
28 with no guarantee of identifying a viable geothermal resource

- 1 • Drilling or feasibility stage:
 - 2 ▶ Flow rates through the production wells may not be sufficient to drive power
 - 3 production, although some of these ‘dry’ wells can be used as injection
 - 4 wells. The probability of drilling a ‘dry’ well is considerably higher for
 - 5 greenfield sites relative to expansion projects, increasing the risk and cost.
 - 6 ▶ The heat flow from the reservoir may not be sustainable over the lifetime of
 - 7 a prospective power project if the heat within the reservoir cannot be
 - 8 replenished quickly enough
 - 9 ▶ The drilling program is expensive (more than \$5 million per well drilled) with
 - 10 no guarantee of a financially viable project
- 11 • Construction stage:
 - 12 ▶ Some of the B.C. geothermal resources are located in remote areas or
 - 13 associated with land conservancies, making permitting of the necessary
 - 14 infrastructure challenging in some instances

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|--|--|------------------------------------|
| Geothermal | Survey, except Meager Creek which is Feasibility | High | High (-10 per cent / +60 per cent) |

15 **5.2.7 Run-of-River**

16 There are no fundamental methodology changes in the 2013 Run-of-River (RoR)

17 updates, but the potential estimation and cost estimation are updated to reflect the

18 revision provided by Kerr Wood Leidal Associated Ltd. (KWL). These revisions are

19 documented in the memorandum attached to Appendix 8-A. In the 2013 Update, the

20 UECs are calculated at 7 per cent real cost of capital, and are presented in \$2013.

1 **5.2.7.1 Resource Description**

2 A RoR hydroelectricity generation facility diverts a portion of natural stream flows
3 and uses the natural drop in elevation of a river to generate electricity. RoR projects
4 divert some of a river's flow for power generation and leave the remaining flow in the
5 original stream for environmental and social purposes. A weir (i.e., a structure
6 smaller than a dam used for storage hydro) is required to divert flows into the
7 penstocks that lead to the power generation facilities. A RoR project does not
8 require a large impoundment of water.

9 Currently there are 45 RoR facilities with a total installed capacity of 846 MW,
10 generating an average 3,470 GWh/year of energy in B.C., and there are additional
11 32 contracted RoR projects with a total installed capacity of 1,332 MW and average
12 generation of 4,429 GWh/year waiting to be built.

13 **5.2.7.2 Methodology**

14 The 2013 RoR updates maintain the same methodology as in the 2010 ROR. The
15 2010 RoR resource options review was undertaken in collaboration with an external
16 consulting firm KWL, who updated the November 2007 KWL Run-of-river
17 Hydroelectric Resource Assessment study. The study used a GIS Rapid Hydro
18 Assessment Model developed by KWL tool to assess the energy, capacity and cost
19 of selected potential run-of-river generating sites. The updates include:

- 20 • An update to the areas and reaches of streams excluded from the analysis that
21 are considered undevelopable such as: legally protected areas, glaciers,
22 reaches of streams that are used by salmon, and existing and committed
23 project locations
- 24 • Development of a new RoR hydropower inventory for B.C. using a revised /
25 improved optimization methodology that more closely corresponds to
26 hydroelectric projects presently being proposed and developed in B.C.
- 27 • A revised estimate of project costs based on updated cost data in 2011 dollars

1 An analysis was performed to create a high-level inventory of estimated RoR power
2 potential for B.C. using a hydropower assessment model, topographic and
3 hydrologic GIS data. Gross power potential was evaluated at ~100 m length of
4 stream based on the estimated head and design flow. The design flow was
5 estimated as one-and-a-half times the mean annual discharge (**MAD**), an increase
6 from the 2007 design flow. The MAD was estimated in GIS from the annual runoff
7 data developed by the Province (1998) and the head was estimated for penstocks
8 ranging in length from 500 m to 5,000 m in 500 m increments using the Provincial
9 digital elevation model data. The resulting output consists of over 10 million data
10 points representing potential power plant points-of-diversion complete with flow,
11 head and power estimations.

12 *Site Screening/Constraints*

13 This raw dataset of potential power sites was screened for:

- 14 • Legally protected areas including newly designated areas
- 15 • Reaches of streams supporting salmon species (observations)
- 16 • Glaciers identified in new Provincial glacier datasets
- 17 • Stream reaches related to identified Provincial topographic digital elevation
18 model errors
- 19 • Stream reaches that correspond to projects that have existing or committed (not
20 operating) hydroelectric developments with electricity purchase agreements
21 (**EPAs**)

22 *Site Optimization - Updated Methodology*

23 The screened dataset underwent an optimization routine that selects the largest
24 project in a given stream reach with the updated optimization methodology.

1 In 2007, the site optimization and selection methodology found the greatest power
2 per unit length of penstock and found the steepest drop for a given reach of a
3 stream. As an example, if there were two steep drops nearby, the larger of the two
4 was selected. The MAD was used for design flow.

5 The methodology from the 2007 work is a good start for identifying potential sites,
6 but often developers will design a larger project to optimize the cost effectiveness of
7 the project and extract as much capacity and energy as they can from a location,
8 since there are many costs that are less sensitive to the size of the project and
9 comprise a large portion of the costs (such as access roads and power lines). This
10 generally results in a project that extends beyond the steepest drop in a reach of the
11 stream and a design flow typically 50 per cent greater than what would have been
12 estimated in 2007.

13 Both the old (2007) and new (2010) methodologies consider the steepest section of
14 the stream, however the 2010 methodology generally selected a larger project with
15 the steepest section encompassed by the new potential project. The new
16 optimization results in a change to the project layout size (length of diverted stream
17 and head) and a higher design flow. It selects the largest project on a given stream
18 which is optimized to find the greatest change in gross power over the change in
19 penstock length. This effectively finds the steepest drop of a stream reach and also
20 includes nearby steep channel sections and nearby steep drops in the total length of
21 the penstock. In addition to this, a larger design flow was used (150 per cent of
22 MAD).

23 The 2010 methodology resulted in an estimated project size (capacity and energy)
24 that is believed to be a closer representation of what might be developed for that
25 reach of stream. In many cases it results in more capacity and energy and often with
26 lower UECs than using the methodology applied in the 2007 study.

1 *Energy Estimates*

2 Regional hydrology analysis was carried out to develop an estimate of energy
3 production. This involved data from a statistical analysis of Water Survey of Canada
4 (**WSC**) hydrologic data, and used GIS capabilities to distribute the resulting statistics
5 to the proposed project locations. Annual energy production, firm energy and
6 dependable capacity, were estimated based on flow duration curves. Minimum flow
7 releases for fish were assumed to be 15 per cent of mean annual flow. Flow duration
8 curves were selected for each potential site based on regional WSC gauges in their
9 hydrologic zone.

10 Average annual energy was estimated based on the total quantity of energy that
11 could be generated annually, on average, based on the flow duration curve for the
12 entire period of record for the selected WSC gauge at each potential site. Firm
13 energy was estimated as the total quantity of energy that is generated in the lowest
14 flow year (October to September) in the period of record for the selected WSC
15 gauge at each potential site. The dependable capacity was estimated from the
16 monthly flow duration curves as capacity that can be generated 85 per cent of time
17 in December and January.

18 The seasonal energy profile was based on monthly capacity factors derived from
19 monthly flow duration curves for regional WSC hydrometric stations to estimate
20 energy production by month.

21 The FELCC and ELCC of the potential sites were determined by BC Hydro using
22 models dealing with the loss of load analysis.

23 *Cost Estimation*

24 In the 2010 Report, resource costs were estimated in 2011 dollars using information
25 from constructed project costs, contractors' and manufacturers' quotes and
26 engineering judgement. In the 2013 Update, resource costs are adjusted for
27 inflationary impact and are presented in \$2013. This information was used to

1 develop a series of cost curves (such as penstock, intake and powerhouse civil
2 works, generating equipment, transmission) to estimate costs for each potential site
3 based on key project parameters such as project capacity (MW). A least-cost path
4 routing method was used to estimate the cost of roads and power lines to existing
5 infrastructure.

6 Costs are composed of capital costs and annual costs. Capital costs include costs
7 such as penstock, civil work, generation equipment, construction camp and
8 transportation etc. Annual costs include such as OMA costs, water rental costs,
9 property taxes and land allowance costs.

10 The UEC was estimated for each potential site based on the estimated capital and
11 annual costs, annual energy production, project life, and discount rate.

12 Estimated earliest ISDs vary based on project size and the estimated number of
13 years required for licensing, design, and construction.

14 Details of the 2013 RoR resource options update are presented in Appendix 8.

15 **5.2.7.3 Technical and Financial Results**

16 A summary of the technical and financial results for the RoR resource option is
17 contained in [Table 5-8](#).

1

Table 5-8 Summary of Run-of-river Potential

| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|----------------------------|---------------------------|--------------------------------|------------------|---------------------------------|--------------------------------------|--------------------------------------|
| Peace River | 6 | 55 | 2 | 158 | 88 | 210-490 |
| North Coast | 260 | 2027 | 226 | 7,232 | 5,786 | 114-495 |
| Central Interior | 62 | 616 | 43 | 1,950 | 1,597 | 168-500 |
| Kelly Nicola | 101 | 783 | 31 | 2,277 | 1,809 | 97-494 |
| Mica | 101 | 786 | 32 | 2,452 | 1,928 | 123-499 |
| Revelstoke | 123 | 828 | 32 | 2,383 | 1,648 | 134-499 |
| Vancouver Island | 163 | 1,754 | 420 | 6,322 | 4,802 | 105-499 |
| Lower Mainland | 173 | 1,551 | 310 | 5,443 | 4,189 | 93-495 |
| Selkirk | 44 | 405 | 13 | 1,182 | 835 | 125-497 |
| East Kootenay | 136 | 773 | 41 | 2,481 | 1,861 | 124-500 |
| Total | 1,169 | 9,579 | 1,149 | 31,880 | 24,543 | 93-500 |

2

Note: The table presents results for run-of-river resources under \$500/MWh.

3

A map showing the provincial distribution of the potential RoR resource option is shown in Appendix 5.

4

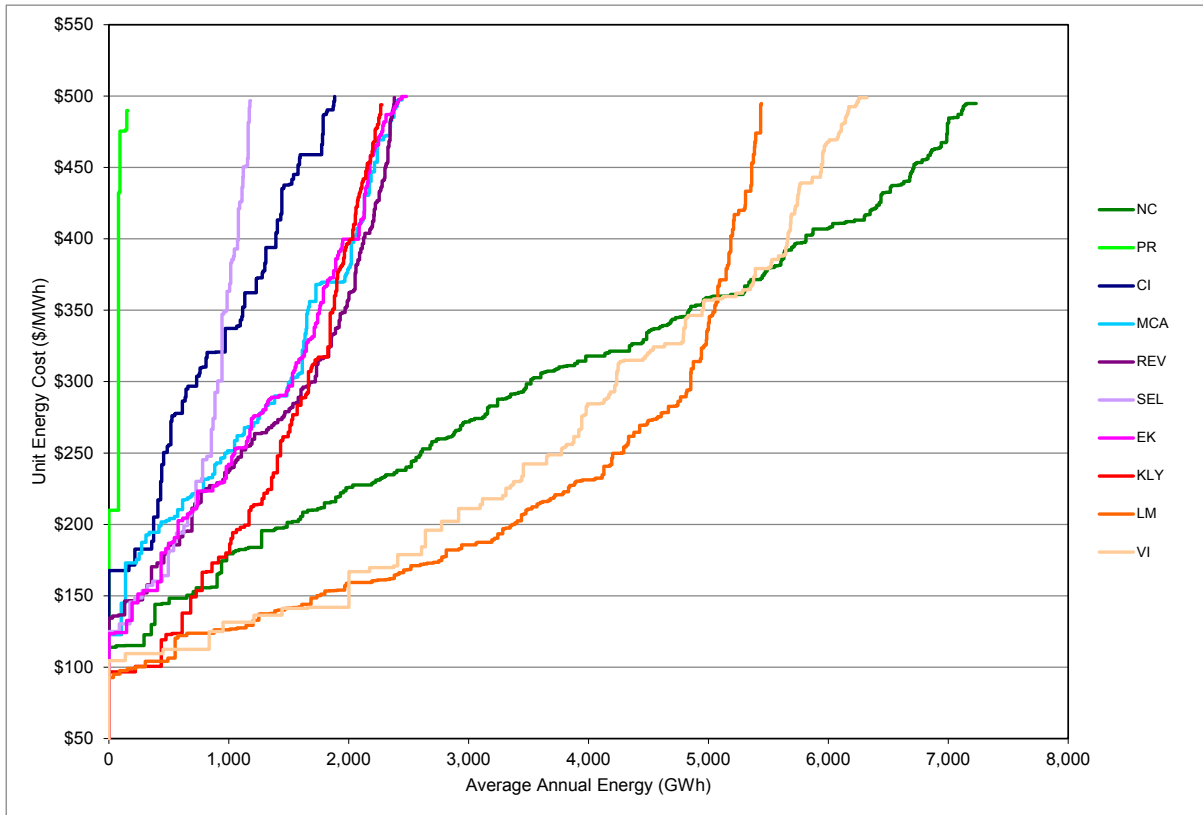
5

The supply curves for RoR resource potential based on POI costs, by transmission region, are shown in [Figure 5-11](#).

6

1

Figure 5-11 Run-of-river POI Supply Curves



2 Note: This figure presents results for run-of-river resources under \$500/MWh.

3 **5.2.7.4 Environmental and Economic Development Attributes**

4 The environmental attributes of the RoR resource bundles are presented in
 5 Appendix 2 and summarized in Appendix 3.

6 The economic development attributes of the RoR resource bundles are presented in
 7 Appendix 4 and summarized in Appendix 3.

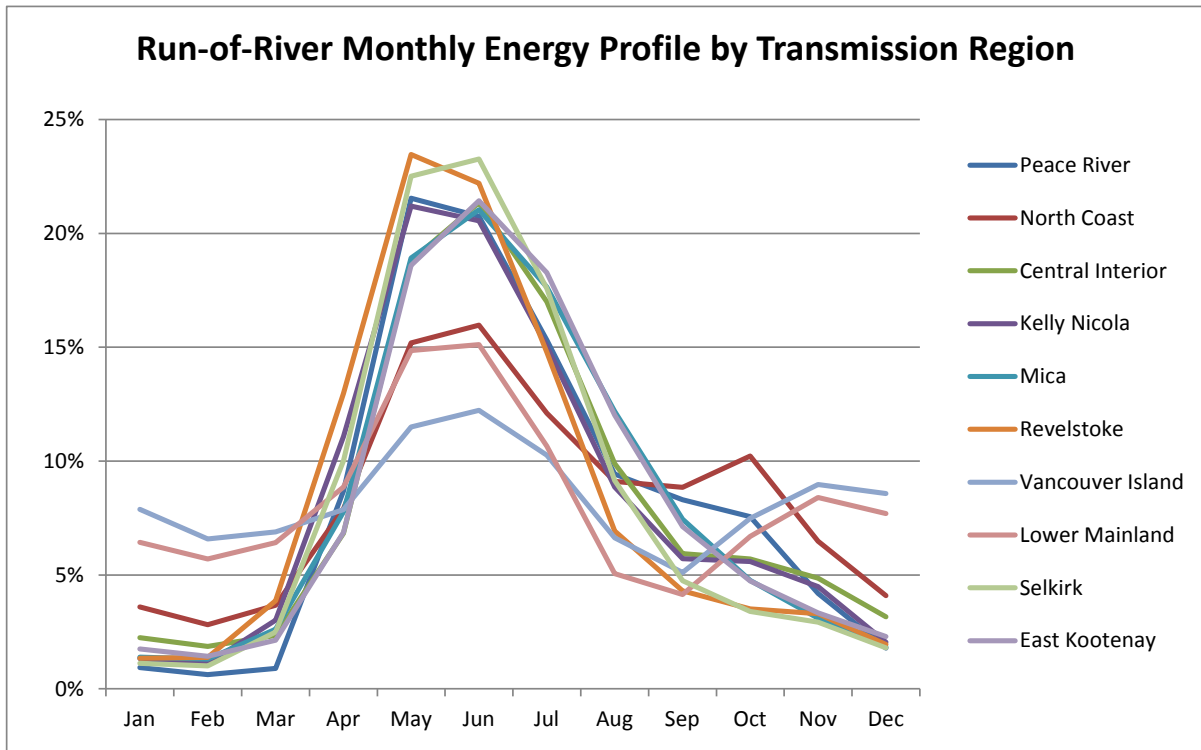
8 **5.2.7.5 Earliest In-Service Date**

9 The earliest ISD for additional RoR generation is estimated to be 2017.

1 **5.2.7.6 Seasonality and Intermittence**

2 The seasonality of the potential RoR resources is shown in [Figure 5-12](#). The RoR
 3 energy profiles are reported by transmission region once interconnection
 4 requirements are considered.

5 **Figure 5-12 Normalized Monthly Run-of-river Energy**
 6 **Profiles by Transmission Region**



7 Note: This figure presents results for run-of-river resources under \$500/MWh.

8 RoR resource options have seasonal characteristics in that much of the power
 9 generation potential is in the freshet period, when the BC Hydro system may already
 10 be operating under generation constraints.

1 **5.2.7.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|----------------|--|--------------------------------------|
| Run-of-river | Survey | Low | Medium (-10 per cent / +40 per cent) |

2 **5.2.8 Pumped Storage**

3 Several North Coast Pumped Storage sites identified after the 2010 ROR are
 4 included in this 2013 ROR Update. The fixed OMA costs have been changed to
 5 reflect changes in maintenance costs of different types of Pumped Storage facilities
 6 (freshwater, saltwater, etc.). In the 2013 Update, the UCCs are calculated at a
 7 7 per cent real cost of capital (except for the Mica site where a value of 5 per cent is
 8 used reflecting BC Hydro’s ownership), and are presented in \$2013.

9 **5.2.8.1 Resource Description**

10 Pumped Storage (**PS**) units use electricity from the grid, typically during light load
 11 hours, to pump water from a lower elevation reservoir to an upper elevation
 12 reservoir. The water is then released during peak demand hours to generate
 13 electricity. Reversible turbine/generator assemblies or separate pumps and turbines
 14 are used in PS facilities. PS units are a net consumer of electricity due to the
 15 inherent inefficiencies in the pumping-generating cycle resulting in an ability to
 16 recover only approximately 70 per cent of the energy used during pumping.
 17 However, the ability to store water and release it during times of system need makes
 18 PS a useful capacity resource. PS units can respond quickly to variations in system
 19 demand and can provide ancillary services such as voltage regulation.

20 There are over 100 GW of PS installed worldwide and it is the most widespread
 21 energy storage system in use on power networks. However, there are no
 22 commercial PS facilities in British Columbia. Of the installed worldwide capacity, the
 23 majority utilize freshwater and surface reservoirs, although facilities that use an

1 ocean as a lower reservoir also exist. The use of underground caverns as a lower
2 reservoir has also been explored.

3 **5.2.8.2 Methodology**

4 BC Hydro engaged Knight Piésold to identify greenfield PS potential in the Lower
5 Mainland, Vancouver Island, and North Coast regions. The study investigated
6 potential greenfield conventional facilities that use freshwater and surface reservoirs,
7 as well as unconventional facilities such as those that use seawater. The study
8 identified technical and economic parameters of potential sites at a conceptual level.

9 Hatch Ltd. was engaged to assess the cost of installing a pump-turbine or a pump at
10 Mica Generating Station, building upon the work presented in the Hatch study on
11 Mica in 2008.

12 The PS reports are presented in Appendix 9.

13 **5.2.8.3 Technical and Financial Results**

14 A summary of the technical and financial results for the PS resource option is
15 contained in [Table 5-9](#). As PS is considered a capacity option, only the UCCs are
16 shown.

17 **Table 5-9 Summary of Pumped Storage Potential**

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | UCC at POI Range (\$2013/kW·year) |
|---------------------|--------------------|-------------------------|----------------|-----------------------------------|
| Kelly Nicola | 4 | 4,000 | 4,000 | 121 – 163 |
| Mica | 1 | 500 | 465 | 100 * |
| Vancouver Island | 84 | 79,000 | 79,000 | 128 – 333 |
| Lower Mainland | 105 | 105,000 | 105,000 | 118 – 318 |
| North Coast | 50 | 37,000 | 37,000 | 119 – 630 * |
| Total | 244 | 225,500 | 225,465 | 100 – 630 |

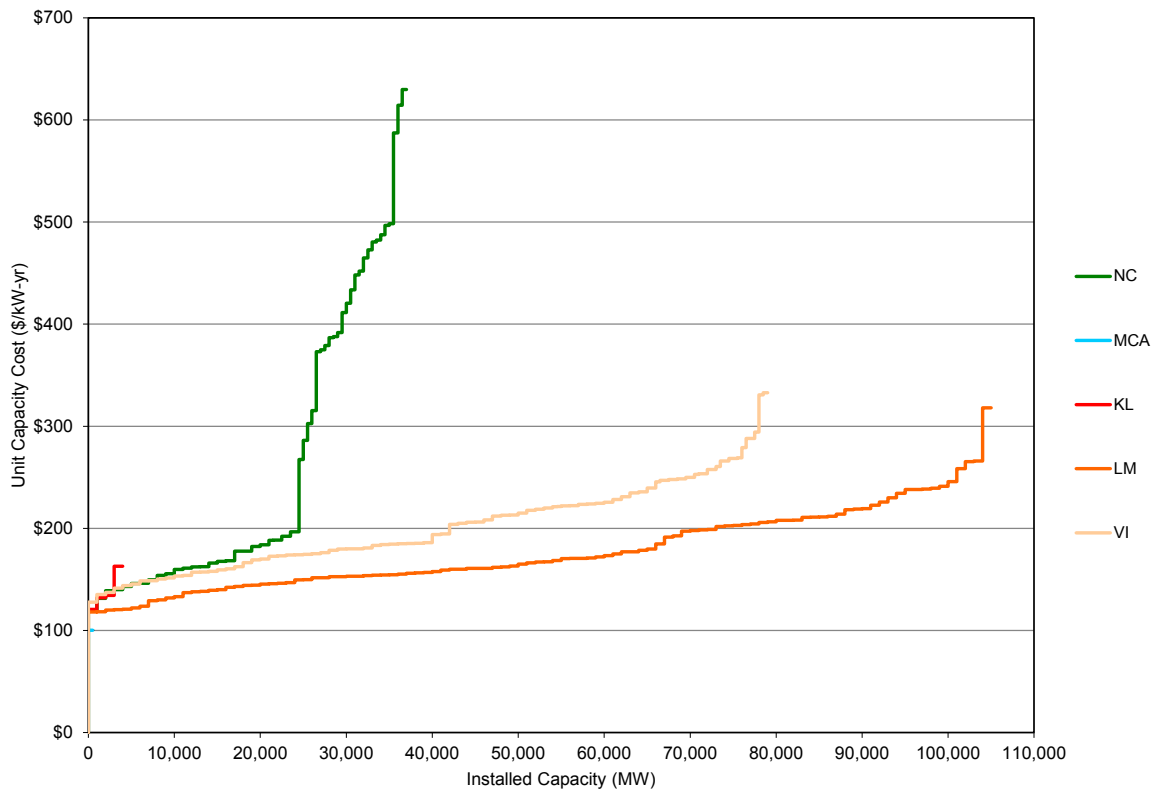
18 Notes:

- 19 1. UCCs for pumped storage include fixed costs only.
20 2. Mica Pumped Storage UCC is calculated at 5 per cent real cost of capital.
21 3. North Coast UCCs are at plant gate; transmission and road access cost components are not included.

1 A map showing the distribution of the potential PS resource option (excluding the
 2 North Coast potential) is shown in Appendix 5.

3 The supply curves for PS potential in the transmission regions investigated, based
 4 on POI costs, are shown in [Figure 5-13](#).

5 **Figure 5-13 Pumped Storage POI Supply Curves**



6 **5.2.8.4 Environmental and Economic Development Attributes**

7 The environmental attributes of the PS resource option are presented in Appendix 2
 8 and summarized in Appendix 3. The environmental impact of reservoir drawdowns
 9 has not been characterized due to data limitations.

10 The economic development attributes of the PS resource option are presented in
 11 Appendix 4 and summarized in Appendix 3.

1 **5.2.8.5 Earliest In-Service Date**

2 The earliest ISD for the Mica PS option is 2019. The earliest ISD for pumped storage
3 is 2021 for the Lower Mainland/Vancouver Island/North Coast greenfield pumped
4 storage sites.

5 **5.2.8.6 Seasonality and Intermittence**

6 There are no seasonality or intermittence issues related to the PS resource option.

7 **5.2.8.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|---------------------------|-----------------|--|------------------------------------|
| Pumped Storage Greenfield | Survey | High | High (-10 per cent / +60 per cent) |
| Pumped Storage – Mica | Pre-Feasibility | Medium | High (-10 per cent / +60 per cent) |

8 **5.2.9 Large Hydro - Site C**

9 Site C is updated based on the information provided in the Site C Environmental
10 Impact Statement (EIS) submission filed in January 2013. The UEC is calculated at
11 5 per cent real cost of capital, and are presented in \$2013.

12 **5.2.9.1 Resource Description**

13 The 2010 *Clean Energy Act (CEA)* prohibits electricity generation projects with
14 storage in excess of prescribed capabilities, and explicitly excludes 11 large hydro
15 projects. As a result, for the 2010 ROR, the only project considered as a potential
16 large hydro resource option is the project commonly known as Site C.

17 The Site C Clean Energy Project (**Site C**) is a proposed third dam and hydroelectric
18 generating station on the Peace River in northeast B.C. Site C would be located
19 downstream from the existing Williston Reservoir and two existing BC Hydro
20 generating facilities (G.M. Shrum and Peace Canyon). It would include an earthfill
21 dam, approximately 1,050 m in length, and 60 m high above the river bed. The
22 reservoir would be 83 km long and would be, on average, two to three times the

1 width of the current river. It would have relatively little fluctuation in water levels, with
2 a proposed maximum normal operating range of 1.8 m. Site C would provide
3 approximately 1,100 MW of dependable capacity, and produce more than
4 4,700 GWh/year of firm energy (5,100 GWh/year average).

5 As the third dam and generating station on the Peace River, Site C would gain
6 significant efficiencies by taking advantage of water already stored in the Williston
7 Reservoir upstream to generate electricity. As a result, Site C would generate about
8 35 per cent of the electricity produced at the W.A.C. Bennett Dam, with only
9 5 per cent of the reservoir area. Site C would be a publicly owned heritage asset,
10 with a significant upfront capital cost, low operating costs and a long life of more
11 than 100 years.

12 BC Hydro recently submitted a Site C EIS with federal and provincial regulatory
13 agencies. The EIS describes the project rationale, its potential effects — including
14 environmental, social, economic, heritage and health — and proposed measures to
15 avoid or mitigate adverse effects. It also includes the benefits Site C would provide
16 to customers, Aboriginal groups, northern communities, and the province. The
17 complete EIS can be found on the regulatory agencies' websites at:

18 www.eao.gov.bc.ca or www.ceaa.gc.ca. Additional information on Site C is available
19 at: www.bchydro.com/sitec.

20 **5.2.9.2 Methodology**

21 The data in this report is based on the updated project design and cost estimate and
22 is consistent with the information provided in the Site C EIS submission filed in
23 January 2013.

24 **5.2.9.3 Technical and Financial Attributes**

25 [Table 5-10](#) summarizes the technical and financial characteristics of Site C.

1

Table 5-10 Site C Summary

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|----------|--------------------------|-------------------------------|-------------------------------|
| Peace River | 1 | 1,100 | 1,100 | 5,100 | 4,700 | 83 |

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Note: Based on capital cost of \$7.9 billion. The UEC in the table above includes sunk costs. For portfolio analysis sunk costs to March 31, 2013 are removed, which reduces the UEC to \$76/MWh in 2011\$. UEC value is presented using a 5 per cent real cost of capital. The Site C UEC at the previous 6 per cent real cost of capital is \$95/MWh.

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A map showing the location of Site C is presented in Appendix 5.

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5.2.9.4 Environmental and Economic Development Attributes

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The environmental attributes of the Site C resource option are presented in Appendix 2 and summarized in Appendix 3.

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The economic development attributes of the Site C resource option are presented in Appendix 4 and summarized in Appendix 3.

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The environmental and economic development attributes for the Site C project use a similar methodology to other projects investigated as part of the 2010 ROR. These attributes do not represent the detailed effects of the project. Rather the high-level environmental footprints and economic development attributes are used for comparison of resource options across provincial-scale portfolios, and act as proxies for more detailed environmental, social, and heritage effects of potential projects. The detailed effects of the Site C project on environmental, heritage, social, economic and health resources are evaluated as part of the environmental assessment (EA) process, according to the methodologies required by the Site C Environmental Impact Statement Guidelines.

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5.2.9.5 Earliest In-Service Date

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The Site C project requires environmental certification and other regulatory permits and approvals before it can proceed to construction. In addition, the Crown has a duty to consult and, where appropriate, accommodate Aboriginal groups. The Site C project schedule is based on the regulatory process established as part of the joint

1 B.C./Canada agreement for a cooperative environmental assessment process, and
 2 the project construction schedule. The forecast ISD for the Site C Clean Energy
 3 Project is fiscal 2023 for the first generating unit, with all units in service in
 4 fiscal 2024.

5 **5.2.9.6 Seasonality and Intermittence**

6 There are no seasonality or intermittence issues with Site C. It is expected that the
 7 generation flexibility associated with large hydro will help mitigate intermittence
 8 issues associated with other resource options.

9 **5.2.9.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|----------------|--|---------------------------|
| Site C | Feasibility | Medium | Low-Medium* |

10 Note: The Site C cost estimate is a Class 3 cost estimate as defined by the Association for the Advancement of
 11 Cost Engineering (**AACE**). From the AACE classification, "Typical accuracy ranges for Class 3 estimates
 12 are -10 per cent to -20 per cent on the low side, and +10 per cent to +30 per cent on the high side, depending on
 13 the technological complexity of the project, appropriate reference information, and other risks (after inclusion of
 14 an appropriate contingency determination)."

15 **5.2.10 Resource Smart**

16 BC Hydro is pursuing the advancement of two capacity Resource Smart projects:
 17 G.M. Shrum Units 1-5 Capacity Increase (referred to as **GMS Units 1-5 Capacity**
 18 **Increase**) and Revelstoke Unit 6. In the 2013 Update, the UCCs are calculated at
 19 5 per cent real cost of capital, and are presented in \$2013.

20 **5.2.10.1 Resource Description**

21 There is some opportunity to modestly increase the energy and/or capacity within
 22 BC Hydro's existing fleet of 30 hydroelectric Heritage assets. These opportunities
 23 are commonly referred to as Resource Smart opportunities.

24 Energy and/or capacity increases can be realized as stand-alone investments
 25 planned specifically to satisfy an energy and/or capacity need identified through the
 26 long range planning process, or the opportunities can be realized at the time of

1 reliability refurbishment or replacement investments associated with the major
2 generating components. The capability of all of the major generating components
3 (generator, turbine, unit transformer, circuit breaker, exciter, governor, water
4 passage) and auxiliary equipment have to be able to facilitate the increased energy
5 and capacity requirements so in some cases it can take a long time to fully realize
6 the uprated potential of the Heritage assets if combined with reliability
7 improvements.

8 In recent years, BC Hydro has implemented or is implementing a number of such
9 opportunities. Examples already included in BC Hydro's resource stack as
10 committed resources are:

- 11 • The addition of one unit (500 MW) at Revelstoke Generating Station in the B.C.
12 Interior (Revelstoke Unit 5, in-service in F2011)
- 13 • The addition of two units (appropriately 500 MWs each) at Mica Generating
14 Station in the B.C. Interior (Mica Units 5 and 6 are expected to be in-service in
15 F2015 and F2016, respectively).
- 16 • Increasing the capacity of Units 6 to 8 at the GMS Generating Station, providing
17 additional capacity of approximately 90 MW (in-service in F2013) on the Peace
18 River
- 19 • Replacing the runners at Ruskin Generating Station in the Lower Mainland,
20 adding approximately 9 MW of additional capacity and 28 GWh/year of energy
- 21 • Replacement of the G1 and G2 generator stators at the Cheakamus Generating
22 Station in the Lower Mainland and increase the dependable capacity of each
23 unit by approximately 20 MW each with expected in-service date of
24 September 2017 for Unit 1 and March 2018 for Unit 2
- 25 • The Identification phase of a generator stator reliability improvement capital
26 project is underway with potential to add approximately 4 MW to each of Units 5
27 and 6 at the Bridge River Generating Station

- The Identification Phase of a capital project to explore the feasibility, impacts, and energy capability associated with the dredging of Grohmann Narrows in the Kootenay region

The largest remaining Resource Smart projects identified in terms of additional dependable capacity are:

- GMS Units 1-5 Capacity Increase, which entails upgrades to GMS units 1 to 5 turbines with more efficient turbines to provide up to 220 MW of dependable capacity when all 5 units are rewound
- Revelstoke Unit 6, which entails installation of a sixth unit at Revelstoke with an installed capacity of 500 MW and estimated 488 MW of dependable capacity

5.2.10.2 Methodology

The GMS Units 1-5 Capacity Increase is based on conceptual level estimates and Revelstoke Unit 6 is updated with the most recent project information.

5.2.10.3 Technical and Financial Attributes

A summary of the technical and financial results for the Resource Smart options are contained in [Table 5-11](#).

Table 5-11 Summary of Resource Smart Potential

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UCC at POI Range (\$2013/kW-year) |
|---------------------|--------------------|-------------------------|----------|--------------------------|-------------------------------|-----------------------------------|
| Peace River | 1 | 220 | 220 | TBD | TBD | 35 |
| Revelstoke | 1 | 500 | 488 | 26 | 26 | 50 |

Note:

Peace River numbers are based on conceptual level estimates. The installed capacity and DGC will be in the range of 185 MW to 220 MW.

A map showing the distribution of the potential Resource Smart resource option is shown in Appendix 5.

1 **5.2.10.4 Environmental and Economic Development Attributes**

2 The environmental attributes are presented in Appendix 2 and summarized in
 3 Appendix 3. As this option does not result in a new footprint, a limited number of
 4 attributes are summarized in the RODAT sheets.

5 The economic development attributes are presented in Appendix 4 and summarized
 6 in Appendix 3.

7 **5.2.10.5 Earliest In-Service Date**

8 The earliest ISD for GMS Units 1-5 Capacity Increase project is F2021. The earliest
 9 ISD for the Revelstoke Unit 6 project is F2021.

10 **5.2.10.6 Seasonality and Intermittence**

11 There are no seasonality or intermittence issues with Resource Smart projects.

12 **5.2.10.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|---------------------------------|----------------|--|--------------------------------------|
| GMS Units 1-5 Capacity Increase | Feasibility | Low | High (-35 per cent / +100 per cent) |
| Revelstoke Unit 6 | Feasibility | Low | Medium (-10 per cent / +40 per cent) |

13 **5.2.11 Natural Gas-Fired Generation and Cogeneration**

14 The capital cost for the 100 MW simple cycle gas turbine (**SCGT**) is increased to
 15 reflect recent increases in gas turbine costs. The co-generation resource option is
 16 characterized using a representative project. All other inputs and analysis
 17 assumptions are identical to what were used in the 2010 ROR. In the 2013 Update,
 18 the UECs for the combined cycle gas turbines (**CCGT**) and UCCs for SCGT are
 19 calculated at 7 per cent real cost of capital, and are presented in \$2013.

1 **5.2.11.1 Resource Description**

2 Natural gas-fired generators produce electricity using the heat released by the
3 combustion of natural gas. SCGT and CCGT are the most commonly employed
4 technologies. Conversion efficiencies are typically 35 to 40 per cent for SCGT
5 machines, and 50 to 60 per cent for CCGT machines.

6 Co-generation of both heat and electricity using natural gas as a fuel is another form
7 of natural gas-fired generation. Cogeneration involves electricity production using
8 reciprocating engines or turbines and a steam/thermal host to use the excess heat
9 produced from the generation process. Resource potential is limited by the
10 availability of steam/thermal hosts such as greenhouses, hospitals, universities and
11 industrial facilities that use steam or heat. By using waste heat in a process that
12 requires heating, the efficiency of cogeneration plants is 90 per cent or greater.

13 Gas-fired generation has several advantages:

- 14 • It is a proven technology with low construction cost risk and high operational
15 reliability
- 16 • Generators are available in a range of sizes and configurations, and are
17 capable of supplying large-scale, dependable capacity and firm energy
- 18 • The plants can be sited close to load centres and can be especially useful in
19 serving transmission constrained regions
- 20 • Operation of the generators may be displaced when economic energy (e.g.,
21 secondary hydroelectric energy) is available at prices lower than the cost of gas

22 The primary disadvantages of gas-fired generation include:

- 23 • Production of greenhouse gases (**GHG**) and other air pollutants
- 24 • Natural gas prices can be volatile posing significant cost uncertainty

1 The development of any gas-fired generation in B.C. would need to be within the
 2 allowance made for non-clean resources in the B.C. CEA, except for any generators
 3 built to serve Liquefied Natural Gas (**LNG**) facilities. The CEA states that no more
 4 than 7 per cent of total electricity generation in the province can come from
 5 non-clean sources.

6 **5.2.11.2 Methodology**

7 BC Hydro undertook an in-house update of the cost of some selected gas-fired units.
 8 The main alternatives that are expected to be relevant for resource planning
 9 purposes are a 100 MW SCGT option that can serve as a capacity resource and
 10 50 MW, 250 MW, and 500 MW CCGT’s that can provide both firm energy and
 11 capacity.

12 **5.2.11.3 Technical and Financial Results**

13 A summary of the technical and financial results for the gas-fired generation
 14 resource options are contained in [Table 5-12](#) and [Table 5-13](#).

15 **Table 5-12 Summary of CCGT and Small**
 16 **Cogeneration Natural Gas-Fired**
 17 **Generation Potential**

| Resource Option | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|-----------------------------|--------------------|-------------------------|----------|--------------------------|-------------------------------|-------------------------------|
| 50 MW CCGT in Kelly/Nicola | 1 | 56 | 49 | 300 | 386 | 92 |
| 250 MW CCGT in Kelly/Nicola | 1 | 263 | 236 | 1,450 | 1,861 | 62 |
| 500 MW CCGT in Kelly/Nicola | 1 | 530 | 479 | 2,940 | 3,776 | 58 |
| Small Cogeneration | 1 | 10 | 10 | 80 | 80 | 74 |

18 Notes:

- 19 1. Representative project used to characterize the resource option.
 20 2. UECs are based on natural gas price estimates from BC Hydro’s 2013 Market Scenario 1, and do not include
 21 the cost of GHG offsets or the B.C. carbon tax.

1 As SCGTs are considered to be capacity options, the UCCs are shown in
 2 [Table 5-13](#).

3 **Table 5-13 Summary of the SCGT Natural Gas Fired**
 4 **Generation Potential**

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | UCC at POI Range (\$2013/kW-year) |
|---------------------------------|---------------------------|--------------------------------|-----------------|--|
| 100 MW SCGT in Kelly/Nicola | 1 | 103 | 98 | 84 |
| 100 MW SCGT on Vancouver Island | 1 | 103 | 101 | 180 |

5 Notes:

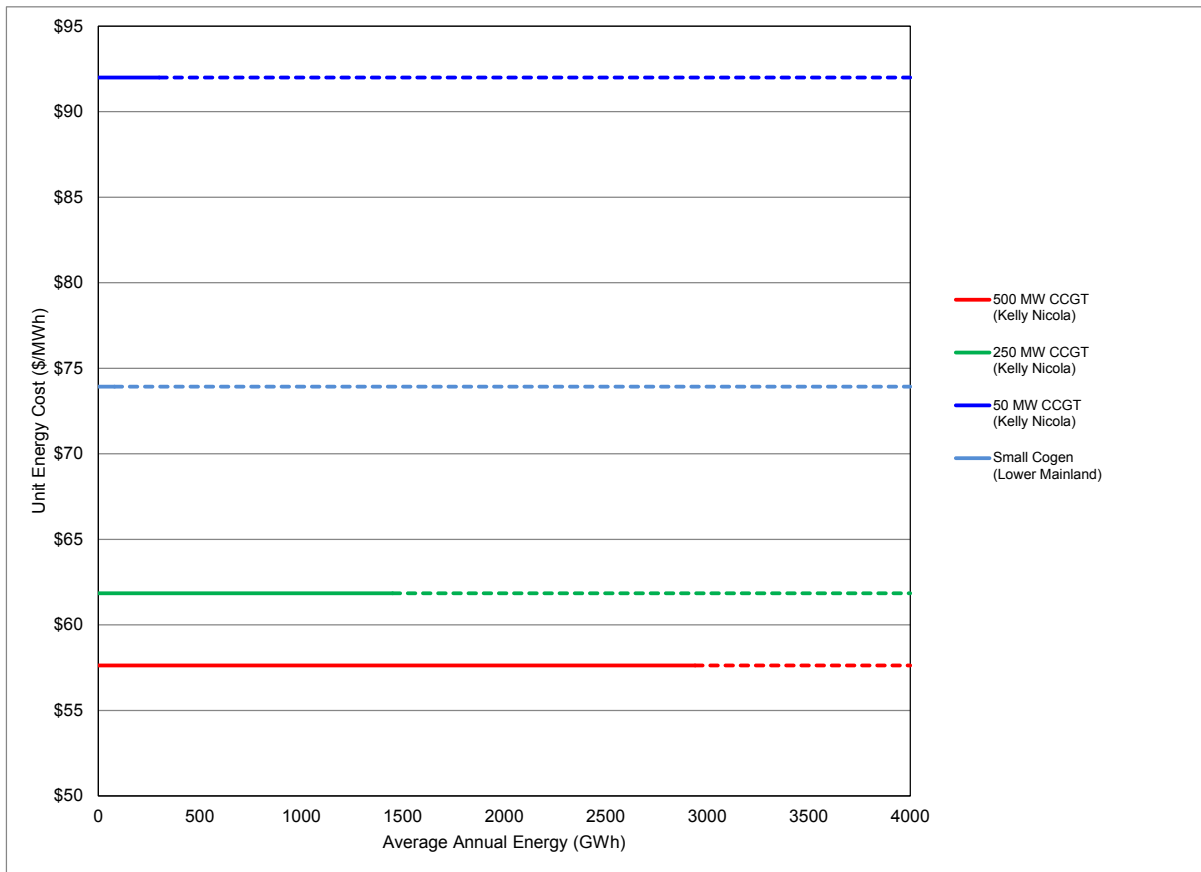
- 6 1. Representative project used to characterize the resource option.
- 7 2. Unit capacity costs for SCGTs include fixed costs only.

8 A map showing representative locations of potential gas-fired generation resource
 9 options is shown in Appendix 5.

10 The supply curves for the CCGT and small cogeneration resource options, based on
 11 POI costs, are shown in [Figure 5-14](#).

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Figure 5-14 CCGT and Small Cogeneration POI Supply Curves*



3 * The solid line indicates the energy contribution of a single representative project. A dotted line indicates
4 additional potential.

5 **5.2.11.4 Environmental and Economic Development Attributes**

6 The environmental attributes of the natural gas-fired generation and small gas
7 cogeneration project options are presented in Appendix 2 and summarized in
8 Appendix 3.

9 The economic development attributes are presented in Appendix 4 and summarized
10 in Appendix 3.

11 **5.2.11.5 Earliest In-Service Date**

12 The earliest ISD for gas-fired resource options is 2017.

1 **5.2.11.6 Seasonality and Intermittence**

2 There is no seasonality or intermittence issues associated with gas-fired resource
3 options.

4 **5.2.11.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|-----------------|--|--------------------------------------|
| Natural Gas | Pre-Feasibility | Medium | High (-10 per cent / +60 per cent) |
| Co-generation | Survey | Low | Medium (-10 per cent / +40 per cent) |

5 **5.2.12 Coal-Fired Generation with Carbon Capture and Sequestration**

6 All inputs and analysis assumptions are identical to what were used in the
7 2010 ROR. In the 2013 Update, the UEC is recalculated at 7 per cent real cost of
8 capital, and is presented in \$2013.

9 **5.2.12.1 Resource Description**

10 In traditional coal-fired power generation, coal is milled to a fine powder allowing it to
11 burn more quickly. The powdered coal is blown into the combustion chamber of a
12 boiler where it is burnt at high temperatures. The hot gases and heat energy
13 produced convert water into steam that is used to generate electricity. Integrated
14 Gasification Combined Cycle (**IGCC**) plants are a newer generation of coal power
15 generation technology. In an IGCC plant, the coal is first gasified to produce a
16 synthetic gas (**syngas**). Syngas is burned in a combined cycle generator to produce
17 electricity. The steam turbine also uses steam created in cooling syngas which
18 contributes to the higher efficiency of IGCC plants, potentially in the 60 per cent
19 range.

20 In B.C., Policy Action No. 20 of the 2007 BC Energy Plan stipulates that coal-fired
21 generation must meet a zero GHG emission standard “through a combination of
22 ‘clean coal’ fired generation technology, carbon sequestration and offset for any

1 residual GHG emission”. While ‘Clean Coal’ technology in the form of IGCC is now
 2 becoming available, technology that allows the carbon dioxide to be captured from
 3 the plant and stored through sequestration, allowing coal-fired generation to have
 4 ‘near zero’ GHG emissions is still evolving and is not presently viable on a large
 5 commercial scale. According to the Electric Power Research Institute (**EPRI 2007**)⁹,
 6 coal-fired plants with 90 per cent CO₂ emission capture and storage could be
 7 commercially available by 2022 (Appendix 10).

8 **5.2.12.2 Methodology**

9 BC Hydro relied upon reports prepared by Powertech Labs Inc. in 2009
 10 (Appendix 10) and a 2007 National Energy Technology Laboratory report¹⁰.

11 **5.2.12.3 Technical and Financial Results**

12 A summary of the technical and financial results for the coal-fired generation with
 13 carbon capture and sequestration (**CCS**) resource option is contained in [Table 5-14](#).

14 **Table 5-14 Summary of Coal-Fired Generation with**
 15 **CCS Potential**

| Transmission Region | Number of Projects | Installed Capacity (MW) | DGC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|----------|--------------------------|-------------------------------|-------------------------------|
| Peace River | 1* | 745 | 556 | 3,896 | 3,896 | 88 |

16 * Representative project used to characterize the resource option.
 17 The dependable capacity was discounted to account for the energy used up by the CCS process.
 18 Coal-fired generation with CCS is an emerging technology. There is significant uncertainty around the cost
 19 estimates provided.

20 Appendix 5 presents a map of the potential location assumed for the coal-fired
 21 generation resource option in the 2013 ROR Update.

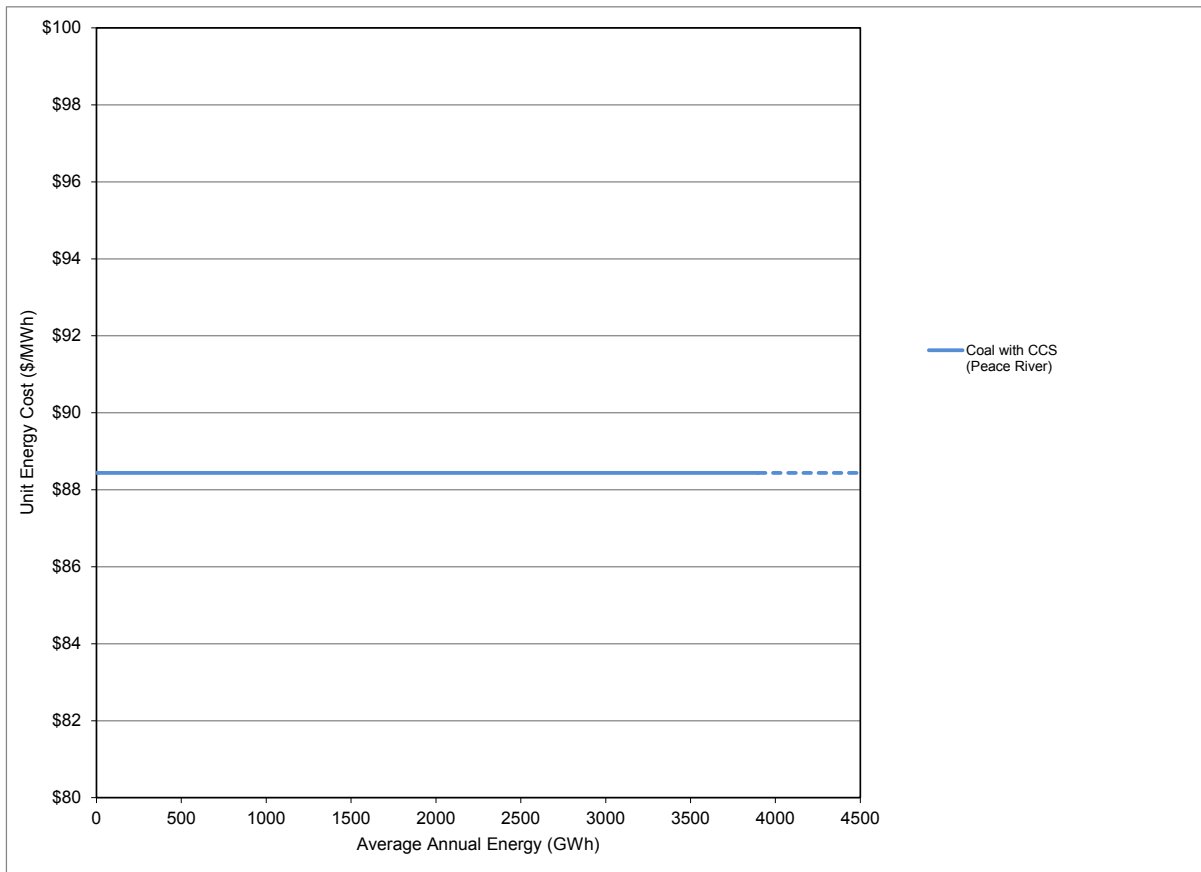
22 The supply curve for the coal-fired generation with CCS resource option, based on
 23 POI costs, is shown in [Figure 5-15](#).

⁹ Fall 2007, EPRI Journal, Pathways to Sustainable Power in Carbon-Constrained Future, page 4-13.

¹⁰ Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report, Revision 1, August 2007.

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Figure 5-15 Coal-Fired Generation with CCS POI Supply Curve*



3 * The solid line indicates the energy contribution of a single representative project. A dotted line indicates
4 additional potential.

5 **5.2.12.4 Environmental and Economic Development Attributes**

6 The environmental attributes of the coal-fired generation with CCS resource option
7 are presented in Appendix 2 and summarized in Appendix 3.

8 The economic development attributes are presented in Appendix 4 and summarized
9 in Appendix 3.

10 **5.2.12.5 Earliest In-Service Date**

11 The earliest ISD for coal-fired generation with CCS in British Columbia is estimated
12 to be 2030.

1 **5.2.12.6 Seasonality and Intermittence**

2 There are no seasonality or intermittence issues with the coal-fired generation with
3 CCS resource option.

4 **5.2.12.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|--------------------------------|----------------|--|------------------------------------|
| Coal-fired Generation with CCS | Survey | High | High (-10 per cent / +60 per cent) |

5 **5.2.13 Wave**

6 All inputs and analysis assumptions are identical to what were used in the
7 2010 ROR. In the 2013 Update, the UECs are recalculated at 7 per cent real cost of
8 capital, and are presented in \$2013.

9 **5.2.13.1 Resource Description**

10 Wave energy is generated by winds blowing over the surface of the ocean. Because
11 ocean waves are a product of the complex interactions among variable local winds,
12 occasional storms or the effects of distant sea conditions, wave energy is a complex
13 and variable phenomenon. The character of the ocean wave state is often
14 summarized in terms of wave height, period, direction and spectral distribution
15 parameters. The wave energy resource is usually characterized by the wave power
16 level, which is the flux of energy per unit length of wave crest (kW/m) that is a
17 function of the square of the wave height and period.

18 The strong winds within the band from 40 to 60 degrees latitude as well as the
19 circumpolar storms contribute to a good potential wave energy resource on the
20 Pacific coast of B.C. and Alaska. In the deep waters of the open Pacific, the wave
21 energy resource is large and consistent over distances on the order of a few
22 hundred kilometres. As waves approach the shore through waters of decreasing
23 depth, waves are modified by complex refraction and diffraction. Wave energy is
24 also dissipated as waves approach shore due to friction with the ocean bottom. As a

1 result, wave energy in shallower water can vary significantly over distances of less
2 than 1 km, and interactions with the shoreline and local bathymetry can create
3 localized wave energy ‘hot spots’.

4 There are five generic approaches to capturing the wave energy resource, each at
5 the early stages of commercial development and each with potential application in
6 B.C.

- 7 • **Attenuator:** Floating multiple-segment device that is arranged and moored
8 in-line with the principal wave direction. Wave crests run along the length of the
9 attenuator, causing flexing between joints. The flexing extracts kinetic energy
10 through hydraulic pumps or similar mechanical-electrical converters.
- 11 • **Point Absorber:** A floating device which absorbs kinetic energy through its
12 movement in the waves, akin to a bobbing fishing lure. The power generated
13 from the device’s motion is then converted into electricity using a hydraulic or
14 electromechanical power conversion system.
- 15 • **Oscillating Wave Surge Converter:** This type of device typically consists of a
16 vertical plate which extracts energy from the ocean waves by moving in a
17 horizontal direction.
- 18 • **Oscillating Water Column:** This type of device consists of a hollow structure
19 that has an open bottom. The wave action inside the column drives the
20 air-column above it. An air-turbine can then be used to convert the air-pressure
21 differential into electricity.
- 22 • **Overtopping Device:** This device typically consists of an enclosed basin into
23 which waves overtop using a ramp. The water inside the enclosed is elevated
24 over the sea-level, creating a low hydraulic head which is converted into
25 electricity using a low-head Kaplan turbine.

26 There are currently no wave energy projects deployed in B.C. waters. However, two
27 wave energy projects have received partial funding from federal and/or provincial

1 funding agencies: a near-shore multi-MW point absorber demonstration to be
2 located near Ucluelet, and a point absorber demonstration unit that will reduce the
3 use of diesel-fuelled generation in a B.C. remote community. Globally, wave energy
4 remains in its infancy, with single units or small arrays in demonstration underway in
5 some European jurisdictions.

6 **5.2.13.2 Methodology**

7 With the available data indicating a fairly homogenous resource¹¹, it is not practical
8 to predict a specific location for wave energy project development. However, as of
9 2010 there has been a demonstrated private sector development interest in
10 16 discrete sites on the B.C. Coast through the application for and granting of
11 Investigate Use Permits and Tenure for wave energy development to the B.C.
12 Integrated Land Management Bureau. These 16 sites are found clustered around
13 the central and northern coasts of Vancouver Island. There are no current
14 applications or granted tenures on the highly-energetic western coast of Haida
15 Gwaii, but owing to the strength of the resource, it is assumed that a development
16 interest may emerge near Haida Gwaii.

17 For the purposes of this report, an assumption has been made that these 16 applied
18 or granted tenure sites as well as a speculative cluster of sites on the west coast of
19 Haida Gwaii represent the developable wave energy resource over the 20-year time
20 horizon. The total theoretical energy for these projects is calculated as the product of
21 the length of the wave energy development perpendicular to the dominant wave
22 direction, which has been estimated based on the GIS map of the Integrated Land
23 Management Bureau (**ILMB**) tenure database, and the incoming wave power for the
24 site from the Canadian Hydraulic Centre (**CHC**)¹² report. The extractable wave
25 energy is related to the theoretical wave energy, but is limited by geographical,
26 environmental and technical considerations. For the purposes of the 2013 ROR, it

¹¹ The near-shore wave energy resource is thought to show much greater variation due to influences of the local bathymetry, but this data is not available at the present time.

¹² CHC, Inventory of Canada's Marine Renewable Energy Resources, April 2006.

1 was assumed that an array of generic wave energy capture devices are notionally
 2 deployed along the length of sites perpendicular to the dominant wave direction and
 3 a simple correlation between incoming wave energy and energy production based
 4 on published device power curves was used to calculate energy production potential
 5 at each site.

6 The costs associated with these wave energy projects have been estimated based
 7 on the cost projections from the UK Carbon Trust report¹³.

8 **5.2.13.3 Technical and Financial Results**

9 A summary of the technical and financial results for the wave resource option is
 10 contained in [Table 5-15](#).

11 **Table 5-15 Summary of Wave Potential**

| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|----------------------------|---------------------------|--------------------------------|------------------|---------------------------------|--------------------------------------|--------------------------------------|
| North Coast | 1 | 143 | 34 | 418 | 418 | 748 |
| Vancouver Island | 15 | 936 | 225 | 2,088 | 2,088 | 440-772 |
| Total | 16 | 1,078 | 259 | 2,506 | 2,506 | 440-772 |

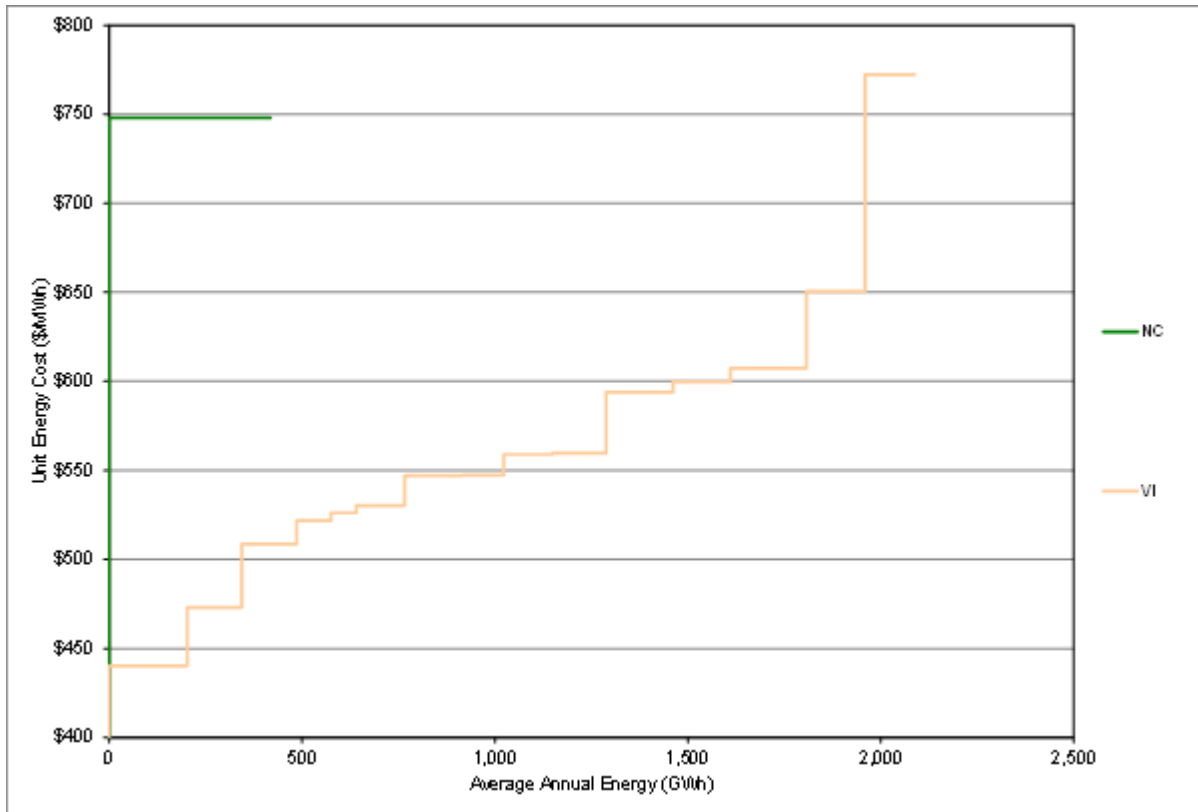
12 A map showing the distribution of the potential wave resource option is shown in
 13 Appendix 5.

14 The supply curves for the wave resource potential, based on POI costs, are shown
 15 in [Figure 5-16](#).

¹³ Future Marine Energy, Results of the Marine Energy Challenge: Cost Competitiveness and Growth of Wave and Tidal Stream Energy, Carbon Trust, January 2006.

1

Figure 5-16 Wave POI Supply Curves



2 **5.2.13.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the wave resource option are presented in
4 Appendix 2.

5 The economic development attributes are presented in Appendix 4.

6 **5.2.13.5 Earliest In-Service Date**

7 The earliest ISD for the wave resource option is 2024.

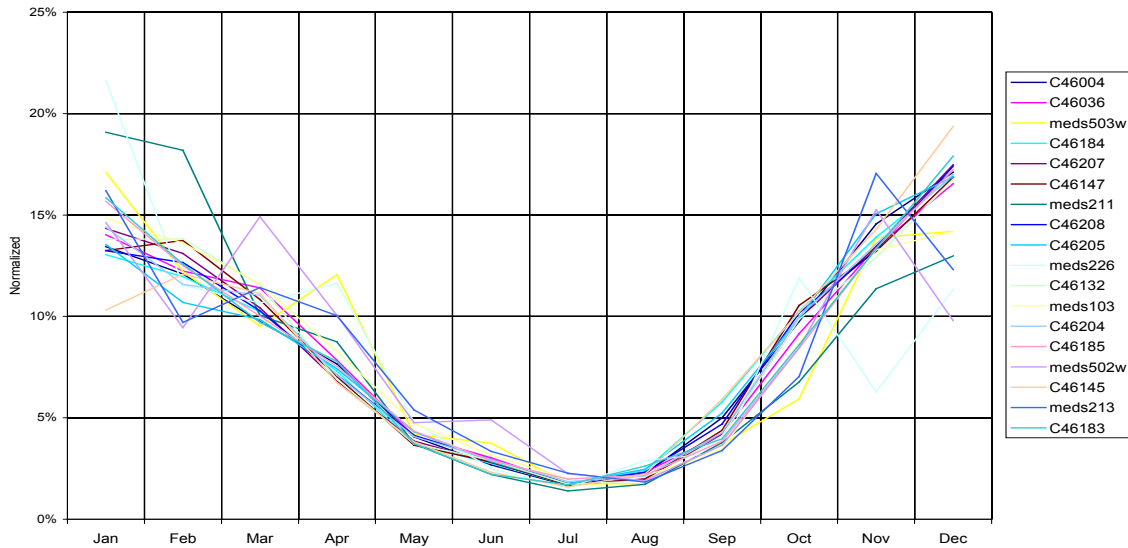
8 **5.2.13.6 Seasonality and Intermittence**

9 For wave energy, the seasonality and intermittence is fundamentally similar to that of
10 offshore wind. There is significant day-to-day variability in wave energy resources in
11 a manner similar to wind energy. There is a pronounced seasonal variability for

- 1 wave energy with a strong peak in the winter months coincident with the BC Hydro
- 2 system peak.

In terms of understanding the seasonality and intermittence of ocean energy, BC Hydro is appreciative of the submission of Ocean Renewable Energy Group (**OREG**) (Appendix 11). BC Hydro reproduced a graph from OREG that provides the monthly energy profile of wave power at measured and modeled locations off the B.C. coast as shown in [Figure 5-17](#) below.

3 **Figure 5-17 Monthly Energy Profile – Wave Potential**



4 **5.2.13.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|----------------|--|------------------------------------|
| Wave | Survey | High | High (-10 per cent / +60 per cent) |

1 **5.2.14 Tidal**

2 All inputs and analysis assumptions are identical to what were used in the
3 2010 ROR. In the 2013 Update, the UECs are recalculated at 7 per cent real cost of
4 capital, and are presented in \$2013.

5 **5.2.14.1 Resource Description**

6 Tidal energy refers to the kinetic energy available in the flow of water driven by the
7 rotation of the Earth in the gravitational fields of the sun and the moon. Tides
8 generally repeat themselves at a regular 24-hour 50-minute interval. However,
9 complex interactions with the gravitational pulls of sun and moon can cause
10 irregularities in the magnitude of the tides. Tidal energy is variable from one hour to
11 the next, but can be precisely predicted years into the future.

12 Tidal energy can be captured in two different ways: tidal barrages and tidal current
13 systems. Tidal barrages involve the construction of a dam in estuaries with a large
14 tidal range to impound water during high tide and exploit the potential energy in the
15 height difference between high and low tides. Tidal barrage is not considered a
16 viable prospect in B.C. This report will focus exclusively on tidal current systems.

17 Tidal current systems, similar to wind energy systems, capture the kinetic energy in
18 fast flowing tidal currents to drive a generator. The electrical generation potential is
19 proportional to the cube of the tidal current velocity, and devices are typically located
20 in areas where the tidal current is accelerated through a narrow channel.

21 There are three fundamental designs of tidal current systems:

- 22 • **Horizontal axis turbines:** the axis of a rotor is horizontal, parallel to the flow of
23 the tidal current
- 24 • **Vertical axis turbines:** the axis of the rotor is vertical, perpendicular to the tidal
25 current

- 1 • **Oscillating hydrofoil:** A hydrofoil is attached to an oscillating arm in the shape
2 of a whale tail. The tidal current flowing across the hydrofoil results in a lift such
3 that the arm swings back and forth across the tidal flow. This motion can then
4 drive fluid in a hydraulic system to be converted into electricity.

5 There are two notable tidal current projects in B.C. Demonstration of a small tidal
6 device at Race Rocks, provided power to the Pearson College ecological education
7 and research centre, reducing the need for diesel-powered generation. A planned
8 tidal current demonstration at Canoe Pass near Campbell River has received federal
9 and provincial funding to install two-times 250 kW vertical axis turbines connected to
10 the BC Hydro grid.

11 **5.2.14.2 Methodology**

12 The CHC report identifies the individual sites in B.C. with a mean annual tidal flow
13 velocity sufficient to justify a theoretical tidal energy project. For these sites, the
14 theoretical tidal energy resource is calculated based on the cube of the tidal flow
15 velocity. The actual extractable energy at these sites is related to the theoretical
16 energy resource, but is limited by geographical and environmental considerations
17 unique to the site, and by technological constraints related to the efficiency of the
18 tidal devices. For the purposes of this ROR, it was assumed that the combined
19 geographical, environmental and technical considerations would limit the tidal
20 energy extraction to 20 per cent of the theoretical tidal energy available at each of
21 the sites identified in the CHC report. It is recognized that the geographies and
22 environmental considerations at the individual sites may permit more or less than
23 20 per cent of the theoretical energy to be extracted, but specific evaluations are
24 beyond the scope of this study.

25 The simple sum of the extractable energy from all sites identified in the CHC report
26 may be an over-estimate of the total extractable resource owing to the dynamic

1 interactions within the B.C. Coastal system. The 2002 Triton study¹⁴ suggests that a
2 mean 600 MW can be extracted from the B.C. Coastal system with modest
3 reductions in tidal flows or environmental impacts. The 600 MW figure represents
4 maximum energy that can be extracted from the system, of which approximately
5 33 per cent can be converted into electricity after accounting for inefficiencies in the
6 tidal generation technologies. In order to estimate within an order of magnitude the
7 total extractable energy from the B.C. system, only the larger sites with an estimated
8 theoretical energy potential of at least 75 MW was included in the ROR, with a
9 threshold of not more than mean 600 MW extracted from the entire system. In
10 essence, this calculation assumes a maximum of 20 per cent of the available kinetic
11 energy is extracted from each potential site, of which one-third is converted into
12 electricity. A capacity factor is estimated for each site based on the average tidal
13 velocity in order to estimate installed capacity.

14 Owing to the early state of commercial development, there is no real-world
15 experience with the capital and long-term operating costs associated with tidal
16 power at the commercial scale. In 2006, the UK Carbon Trust assessed the future
17 costs and potential growth of marine renewables based on the results of their
18 \$4.8 million, 18-month long Marine Energy Challenge. The Carbon Trust report
19 represents an unbiased assessment of generic tidal energy costs at the commercial
20 scale.

21 **5.2.14.3 Technical and Financial Results**

22 A summary of the technical and financial results for the tidal resource option is
23 contained in [Table 5-16](#).

¹⁴ Green Energy Study for British Columbia, Phase 2: Mainland, Tidal Current Energy, October 2002, prepared for BC Hydro Engineering, by Triton Consultants.

1

Table 5-16 Summary of Tidal Potential

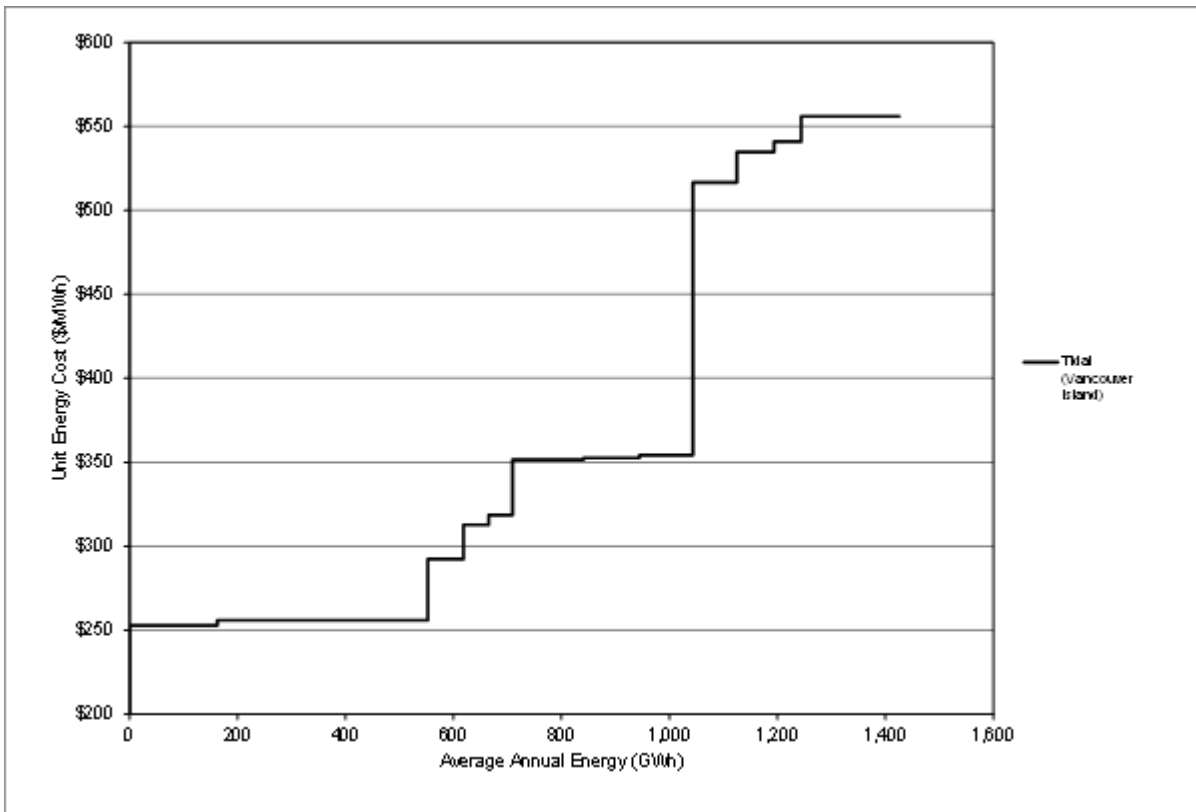
| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|---------------------|--------------------|-------------------------|------------|--------------------------|-------------------------------|-------------------------------|
| Vancouver Island | 12 | 617 | 247 | 1,426 | 1,426 | 253-556 |
| Total | 12 | 617 | 247 | 1,426 | 1,426 | 253-556 |

2 A map showing the distribution of the potential tidal resource option is shown in
 3 Appendix 5.

4 The supply curve for the tidal resource option, based on POI costs, is shown in
 5 [Figure 5-18](#).

6

Figure 5-18 Tidal POI Supply Curve



1 **5.2.14.4 Environmental and Economic Development Attributes**

2 The environmental attributes of the tidal resource option are presented in
3 Appendix 2.

4 The economic development attributes of the tidal resource option are presented in
5 Appendix 4.

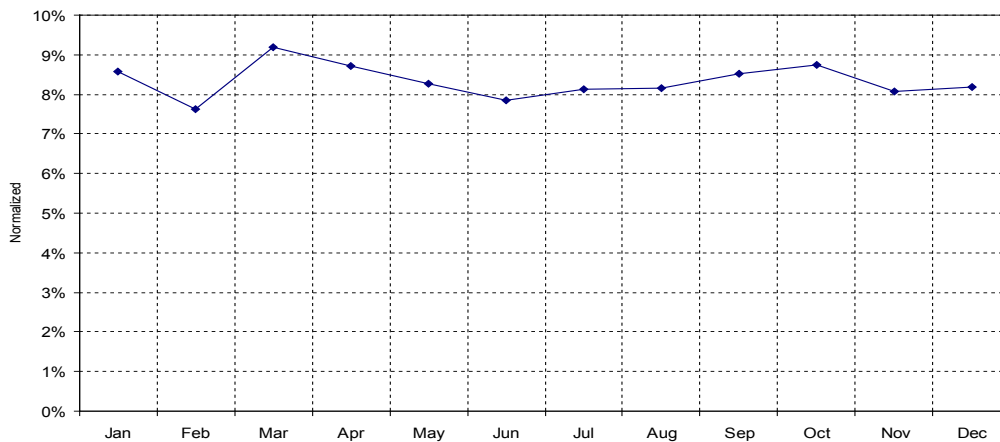
6 **5.2.14.5 Earliest In-Service Date**

7 The earliest ISD for the tidal resource option is 2024.

8 **5.2.14.6 Seasonality and Intermittence**

9 There are no major seasonal trends associated with the tidal resource option. There
10 are predictable intermittency issue associated with the tides given the rise and fall of
11 tides. A monthly energy profile is presented in [Figure 5-19](#).

12 **Figure 5-19 Monthly Energy Profile – Tidal Potential**
13 **(Discovery Passage)**



1 **5.2.14.7 Uncertainty**

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|----------------|--|------------------------------------|
| Tidal | Survey | High | High (-10 per cent / +60 per cent) |

2 **5.2.15 Hydrokinetic**

3 An analysis of the achievable hydrokinetic generation potential in BC is not possible
 4 due to the absence of data describing the raw resource or the expected locations,
 5 sizes and costs of hydrokinetic development projects.

6 *Resource Description*

7 Hydrokinetic energy – also called “river in-stream” or “river current” energy – refers
 8 to the kinetic energy from flowing water in rivers. Hydrokinetic energy systems
 9 convert the kinetic energy in free-flowing rivers into electricity without the use of
 10 dams or diversions. Unlike conventional hydroelectric systems, hydrokinetic systems
 11 do not require a hydraulic head, depending rather on the swift moving river similar to
 12 tidal current or wind energy systems.

13 Hydrokinetic electrical generation potential is proportional to the cube of the river
 14 current velocity, and devices are typically located in areas with fast river currents
 15 and substantial flow volumes for significant portions of the year.

16 There are three fundamental turbine designs:

- 17 • **Horizontal axis turbines:** the axis of a rotor is horizontal, parallel to the flow of
 18 the river current
- 19 • **Vertical axis turbines:** the axis of the rotor is vertical, perpendicular to the river
 20 current.
- 21 • **Paddlewheels:** the axis of the rotor perpendicular to the river current and often
 22 above the surface of the water

1 There are currently no active hydrokinetic demonstration projects in B.C.

2 **5.2.15.1 Methodology**

3 Due to the limited data availability and the absence of a rigorous resource estimate,
4 an assessment of hydrokinetic energy potential in B.C. cannot be presented in this
5 report. Hydrokinetic resources may be updated in subsequent resource estimates
6 following the completion of a National Resources Canada (**NRCan**) study to assess
7 the hydrokinetic resource potential in Canada.

8 **5.2.16 Storage Technologies**

9 The commercial readiness for various storage technologies are updated based on
10 EPRI's 2012 report.

11 **5.2.16.1 Resource Description**

12 Energy storage is now recognised as a key component to future grid asset
13 management and operations. BC Hydro is fortunate in having an abundance of
14 storage in the form of hydro reservoirs. However, there are several possible reasons
15 for installing additional storage at all levels of the power system including the:

- 16 • Potential to defer capital expenditure on transmission or distribution assets
- 17 • Potential to increase the longevity of assets through reduced peak load
- 18 • Potential to decrease any reliance on importing power at peak
- 19 • Potential provision of ancillary services such as voltage and frequency
20 regulation
- 21 • Support of intermittent energy supply

22 Recent advances and focus in development of energy storage have focused on a
23 variety of technologies for a variety of functions within the electrical grid system:

24 Compressed Air Energy Storage (**CAES**) has been used to improve the efficiency of
25 natural gas turbines, compressing the air off-peak and releasing it into the

1 combustion cycle during peak. Compressed air can improve the efficiency of the
2 combustion cycle by as much as 40 per cent. To date this technology has been
3 implemented in large facilities using underground caverns. The technology has been
4 explored for use with intermittent and seasonal renewable energy sources to store
5 energy that is generated but not immediately used to serve load. Smaller scale,
6 above ground CAES systems are currently being assessed for economic viability.

7 Pumped storage is well established commercially as a means to store energy. This
8 resource option is addressed in section [5.2.8](#) of this report.

9 Capacitors store energy in the form of electric charge. As such it can be released
10 very rapidly, which is why these types of systems are used as voltage regulators on
11 transmission and distribution grids. Generally capacitors are used for short bursts of
12 power and are not useful for applications in which energy is required to be
13 discharged over periods of time longer than a few seconds. Advances in capacitors
14 have focused on increasing their energy density. However, these types of devices
15 are still in the early stages of development.

16 Flywheels store energy as inertia or mechanical energy. To date they have been
17 used for reactive power applications with their ability to produce short intense bursts
18 of power. Flywheels can have efficiencies as high as 90 per cent.

19 Batteries come in many different chemistries generally falling into two distinct
20 categories: solid state and flow. Solid state batteries are contained, do not require
21 pumps or other moving parts and rely on the closure of a conducting loop to allow a
22 flow of electrons that either charge or discharge the battery. Flow batteries rely on
23 chemicals that are pumped through a membrane and require periodic refreshing.

24 Solid state battery technologies that are available include Sodium Sulphur (**NaS**),
25 Lithium ion (**Li-ion**), Advanced Lead Acid and Metal Air.

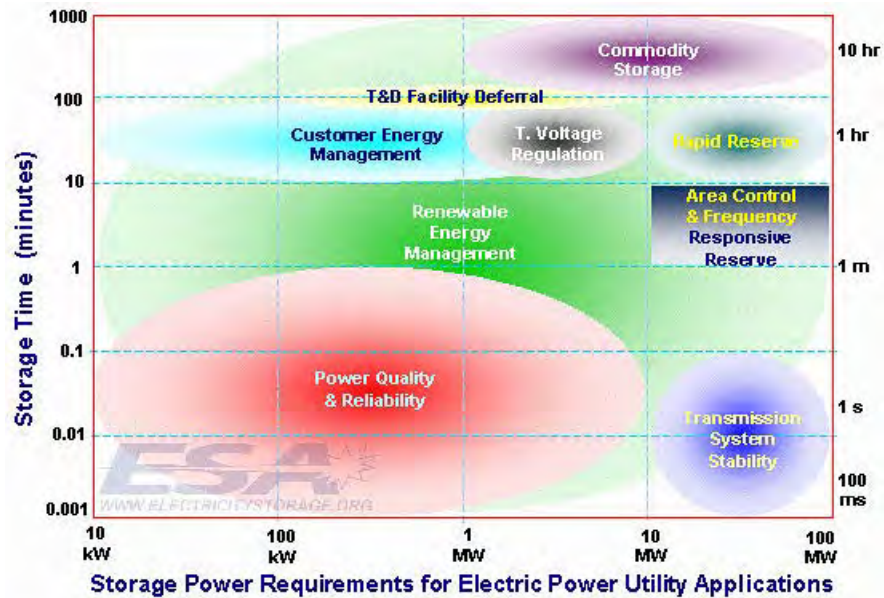
26 Hydrogen Fuel Cell Storage Systems combine electrolyzers with fuel cells to create
27 a means to store electricity. These types of systems have been implemented in

1 some cases where a large excess of energy is needed to be stored (e.g., excess
 2 wind energy) however the current systems suffer from a very poor round-trip
 3 efficiency (< 40 per cent) which makes them unattractive for most applications.

4 [Figure 5-20](#) summarizes the range of applications of existing storage technologies.

5
 6

Figure 5-20 Range of Application of existing Storage Technologies



Data from Sandia Report 2002-1314

7 [Table 5-17](#) summarises the different storage technologies and their respective
 8 commercial readiness.

1
2

Table 5-17 Summary of Storage Technologies and Applications

| Storage Technology | Function | Commercial Readiness¹⁵ |
|---------------------------|---|---|
| CAES | Bulk storage for intermittent renewables | Commercial |
| Pumped storage | Bulk storage for intermittent renewables | Commercial |
| Flywheel | Smoothing of fluctuating intermittent renewables, frequency and voltage regulation | Commercial |
| Capacitors | Frequency and voltage regulation | Commercial at small scale and for high power, low energy applications. Not available for high energy applications |
| Batteries | Distributed energy storage for peak shaving and islanding. Voltage regulation and storage for small scale renewables. | |
| NaS | | Commercial |
| Li-ion | | Early Commercial |
| Adv. Lead Acid | | Demonstration |
| Metal-Air | | R&D |
| Zinc Bromine | | Demonstration |
| Vanadium redux | | Demonstration |
| Fuel cell systems | Storage for medium to large scale renewables | Early Commercial |

3 **5.2.16.2 Methodology**

4 Pumped storage is the only storage resource option that is considered to be within
 5 scope for long-term system planning purposes. The pumped storage resource option
 6 is described in section [5.2.8](#) of the 2013 ROR Update. At this time, no further
 7 assessment of storage options has been undertaken.

¹⁵ Commercial readiness reported as per EPRI “Electricity Energy Storage Technology Options”, 2012

1 **5.2.17 Solar**

2 The cost assumptions are updated to reflect the most recent trends seen at the
3 utility-scale PV plants. In the 2013 Update, the UECs are calculated at 7 per cent
4 real cost of capital, and are presented in \$2013.

5 **5.2.17.1 Resource Description**

6 Solar power, where electricity can be generated from the energy within the sun rays,
7 can be categorized into two main categories: Concentrating Solar Power (**CSP**) and
8 Photovoltaic (**PV**).

9 PV is the other branch of solar power. It converts solar energy directly into
10 direct-current (**DC**) electricity. Unlike CSP which requires high direct irradiation, PV
11 can operate under direct or diffuse solar irradiation. Typically, each module can
12 provide up to 50 to 200 Watts. This technology is small relative to CSP, and is
13 available not only from a utility perspective, but can also be available in residential¹⁶
14 and commercial scale. The two broad categories are crystalline silicon (**c-Si**) and
15 thin films.

16 With silicon being one of the most abundant elements on earth and the c-Si
17 technology fairly mature, it makes up approximately 85 per cent of the global PV
18 market today. Current c-Si has a conversion efficiency of 15 to 20 per cent, best
19 among commercially available technologies.

20 The idea of developing lower cost PV alternatives leads to thin films. Thin films,
21 accounting for most of the remaining PV market, are made of extremely thin layers
22 of photosensitive materials on backing such as glass, stainless steel or plastic. As
23 this technology evolves in search for higher efficiency, semiconductor compounds
24 such as Cadmium Telluride (**CdTe**) and Copper-Indium-Gallium-Diselenide (**CIGS**)
25 are being used. Although thin films have lower materials costs and higher production

¹⁶ Under Rate Schedule 1289 – Net Metering Service, customers with their own generation facilities (up to 50 kW from clean or renewable resources) that produce more than they consume receive a credit from BC Hydro that goes to their account and can be applied against future consumption charges. As of July 2012, there are 168 BC Hydro Net Metering projects in operation, including 149 solar projects.

1 efficiency, they are offset by lower efficiencies relative to c-Si. Among the current
2 types of thin film technologies, the conversion efficiency ranges from 10 to
3 15 per cent. As well, the potential health and safety concerns that Cadmium
4 introduces may discourage increased adoption of this technology.

5 In order to achieve higher performance, a third type of PV is being considered.
6 Similar to the idea of concentrating sunlight to an area like in the CSP, concentrated
7 photovoltaic (**CPV**) technology uses optics such as lenses or curved mirrors to
8 concentrate a large amount of sunlight onto a small area of solar PV cells. Making
9 up less than one per cent of the PV market, CPV has the potential to reach over
10 30 per cent conversion efficiency. Further research and development are required to
11 bring the high cost lower.

12 Concentrating solar power is a technology where with the use of mirrors, it
13 concentrates a large area of sunlight onto a small area. This concentrated light will
14 heat a fluid where the steam produced will then drive a turbine and generates power.
15 In addition, it has the capability for storing heat in insulated containers for usage at a
16 later date. Here are four types of CSP:

17 **Parabolic Troughs:** have large mirrors that shaped like a “U”, and concentrate light
18 onto a receiver pipe along the inside of the curved surface. The solar radiation will
19 heat the fluid inside the pipe, where the steam is then used to generate electricity in
20 a conventional steam generator. It is made to follow the sun during the daylight
21 hours by tracking along a single axis. The collector is aligned North-South and track
22 the sun as it moves from East to West in order to maximize the collection of energy.
23 The parabolic troughs are the most widely commercially deployed CSP plant.

24 **Linear Fresnel:** uses long rows of flat or slightly curved mirrors to capture solar
25 radiation and concentrate them onto a linear receiver tube. Advantage of linear CSP
26 is it uses cheaper flat glass mirrors, and requires less steel and concrete as the
27 metal support structure is lighter. However, it is less efficient than parabolic troughs.

1 **Solar Tower:** utilize a large number of flat solar tracking mirrors called heliostats
2 which concentrate the solar radiation on a receiver at the top of a tower. A heat
3 transfer fluid, which can be water, oil or even molten salt¹⁷, contained in the receiver
4 is used to create steam which spins a conventional turbine that drives an electricity
5 generator. Power towers are more cost effective, offering higher efficiency and better
6 energy storage capability among the CSP technologies.

7 **Dish-Stirling:** utilize a large parabolic solar dish that focuses the solar radiation onto
8 a receiver located at the focal point. The dish is usually coupled with a Stirling
9 engine. Although this technology can achieve the highest efficiency among all CSP
10 technologies, it is still at the demonstration stage and the cost of mass producing
11 this product remains uncertain.

12 Direct Normal Irradiance (**DNI**), the amount of solar radiation from the direction of
13 the sun, is often used to determine whether the location is suitable for CSP. IEA
14 indicated that arid or semi-arid regions between latitude 15° to 40° north or south
15 have the optimal location required to acquire good amount of DNI. According to their
16 CSP roadmap published in 2010, CSP developers typically set a bottom threshold of
17 DNI levels of 1,900 kWh/m²/year to 2,100 kWh/m²/year. Below that, photovoltaic are
18 assumed to have a competitive advantage.

19 **5.2.17.2 Methodology**

20 Due to the various options within CSP and PV, finding one investment, operation
21 and maintenance costs that can be applied to all technologies will be difficult. Aside
22 from material costs, other costs depend on the availability of sunlight, whether the
23 facility has storage capacity and the size of the plant. For example, solar tower, in
24 general, has higher costs than the parabolic troughs; however, its higher efficiency
25 can help in lowering the overall investment costs. According to the

¹⁷ Molten salt raises the potential operating temperature to between 550 to 650 Celsius, enough to allow higher efficiency supercritical steam cycles. In addition, it provides an efficient, low-cost medium in which to store thermal energy.

1 Black & Veatch's (**B&V**) Cost Report¹⁸, the total capital cost for a trough CSP with
2 storage is \$7,060/kW while a tower CSP with storage comes to \$7,040 kW. Due to
3 these high costs and the geographic location in B.C., CSP is deemed to be
4 non-competitive relative to other resources.

5 When considering cost and data in the rest of the section, the focus will be on c-Si.
6 The solar resource assessment and figures assessed in this section is a
7 non-tracking utility PV with a 5 MW install size. Solar isolation data from NRCAN was
8 used to identify the best solar location in ten different areas through the province.
9 The monthly PV potentials were obtained from the NRCAN database. Based on
10 information found in B&V Cost Report, the total capital cost for a utility-scale PV
11 plant is approximately \$2,830/kW, with O&M costs assumed to be \$50/kW-yr. The
12 modules and inverters are considered equipment cost, making up 57 per cent of the
13 total. The at-gate construction, which includes the structures as well as the
14 balance-of-system (i.e., wirings, switches, support racks) are 36 per cent while sunk
15 costs like engineering, procurement, construction management services and owner's
16 cost make up the final 7 per cent.

17 Seasonality was addressed using the monthly profile from NRCAN database.

18 Project lead time for permitting is estimated to be three years, with the construction
19 lead time adding an additional year.

20 **5.2.17.3 Technical and Financial Results**

21 A summary of the technical and financial results for the solar resource option are
22 contained in [Table 5-18](#).

¹⁸ Black and Veatch Cost and Performance Data for Power Generation Technologies Report (February 2012)

1

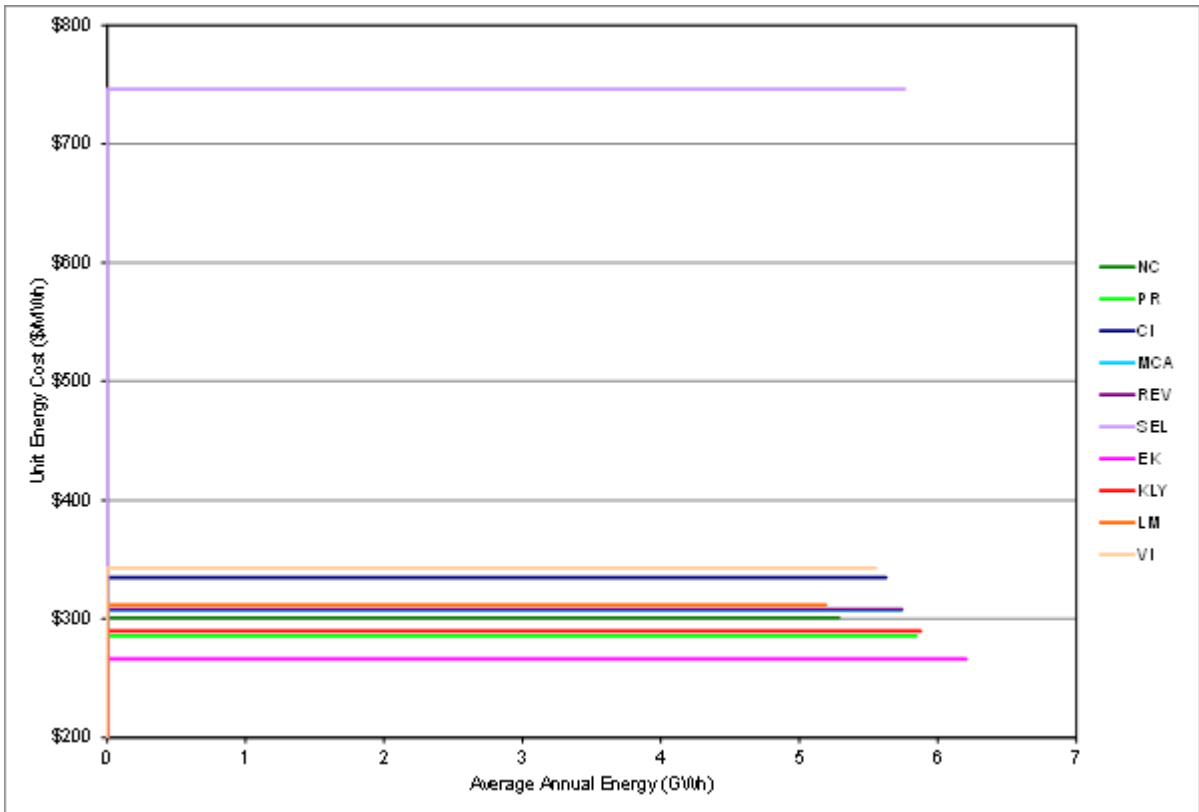
Table 5-18 Summary of Solar Potential

| Transmission Region | Number of Projects | Installed Capacity (MW) | ELCC (MW) | Annual Energy (GWh/year) | Annual Firm Energy (GWh/year) | UEC at POI Range (\$2013/MWh) |
|----------------------------|---------------------------|--------------------------------|------------------|---------------------------------|--------------------------------------|--------------------------------------|
| Peace River | 1 | 5 | 1 | 6 | 6 | 286 |
| North Coast | 1 | 5 | 1 | 5 | 5 | 301 |
| Central Interior | 1 | 5 | 1 | 6 | 6 | 335 |
| Kelly Nicola | 1 | 5 | 1 | 6 | 6 | 290 |
| Mica | 1 | 5 | 1 | 6 | 6 | 307 |
| Revelstoke | 1 | 5 | 1 | 6 | 6 | 308 |
| Vancouver Island | 1 | 5 | 1 | 6 | 6 | 343 |
| Lower Mainland | 1 | 5 | 1 | 5 | 5 | 312 |
| Selkirk | 1 | 5 | 1 | 6 | 6 | 746 |
| East Kootenay | 1 | 5 | 1 | 6 | 6 | 266 |
| Total | 10 | 50 | 12 | 57 | 57 | 266 - 746 |

- 2 A map showing the distribution of the potential solar resource option is shown in
 3 Appendix 5.
 4 The supply curves for the solar resource potential based on POI costs, by
 5 transmission region, are shown in [Figure 5-21](#).

1

Figure 5-21 Solar POI Supply Curves



2 **5.2.17.4 Environmental and Economic Development Attributes**

3 The environmental attributes of the solar resource option are presented in
 4 Appendix 2.

5 The economic development attributes of the solar resource option are presented in
 6 Appendix 4.

7 **5.2.17.5 Earliest In-Service Date**

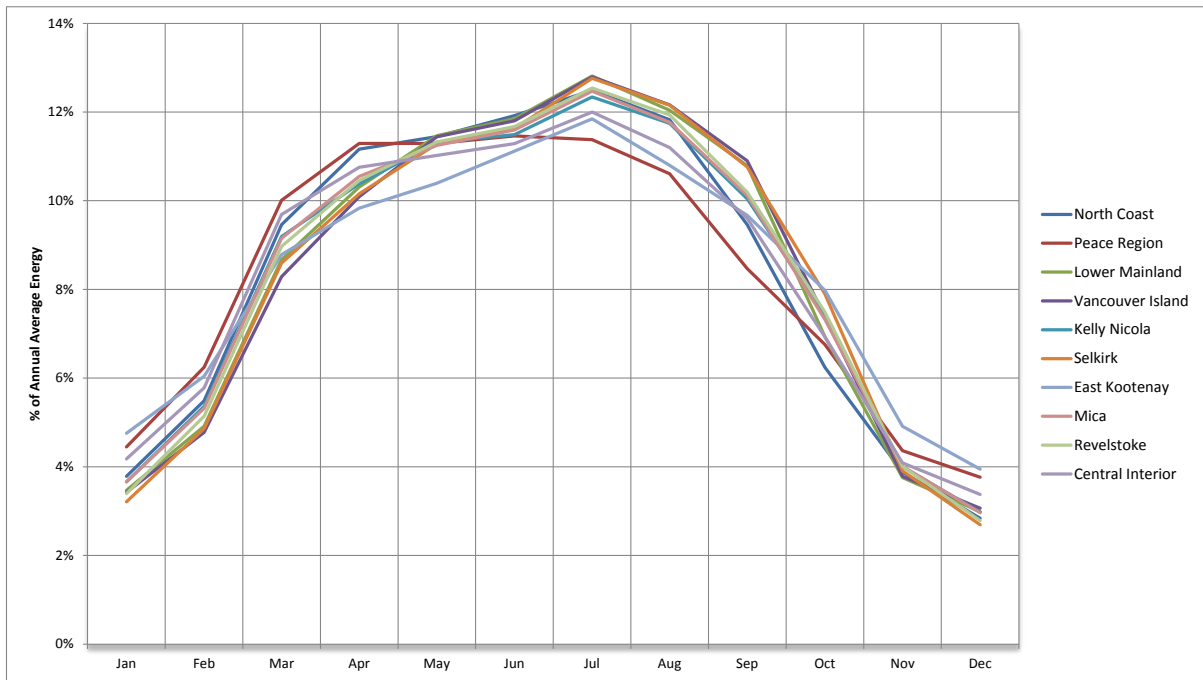
8 The earliest ISD for the solar resource option is 2017.

9 **5.2.17.6 Seasonality and Intermittence**

10 The seasonality of solar resources is shown in [Figure 5-22](#) for each of the
 11 transmission regions.

1
2

Figure 5-22 Normalized Monthly Solar Energy Profiles by Transmission Region



3 In order to concentrate the sunlight in the CSP technology, it needs unobstructed
 4 sunshine, measured in DNI, under clear sky condition. On the other hand, PV
 5 technology can use both direct and diffuse solar radiation. In B.C., solar power
 6 generation is intermittent, pending on the location, the amount of PV potential and
 7 fluctuation in cloudiness.

8 **5.2.17.7 Uncertainty**

9

| Resource Option | Level of Study | Resource Type Related Uncertainty Rating | Cost Uncertainty Criteria |
|-----------------|----------------|--|--------------------------------------|
| Solar | Survey | Low | Medium (-10 per cent / +40 per cent) |

1 **5.2.18 Miscellaneous Distributed Generation**

2 **5.2.18.1 Resource Description**

3 In 2008, BC Hydro began formalizing, in consultation with key stakeholders, a
4 Distributed Generation (**DG**) strategy to explore potential DG across its customer
5 base. For the purposes of this initiative, BC Hydro defined DG as:

6 An approach whereby smaller-scale generation of electricity is
7 located close to the load it is intended to serve, often located at
8 customer sites. It can be contrasted to the traditional model of
9 larger-scale and centralized electricity generation that is located
10 a substantial distance away from load.

11 DG can be either a demand side or supply side resource, or a combination of both.
12 How a customer pursues DG is based on several factors including: the customer's
13 profile and objectives, the specific project, the technology and generation potential,
14 and the cost and value to BC Hydro.

15 BC Hydro undertook the development of a strategic process including pilot projects
16 to help advance DG projects with its customers to better understand the market
17 potential for DG, and recognizing the need to design an efficient and cost-effective
18 process for potential projects given BC Hydro's current suite of power acquisition
19 offers. While DG is not a new concept for BC Hydro or its customers, BC Hydro
20 believes that additional DG potential exists and could be explored. A number of
21 DG-related programs and projects have been completed or are already in place,
22 including:

- 23 • Approximately 250 projects are in service under BC Hydro's net metering
24 program (projects up to 50 kW)
- 25 • 2001 40GWh RFP
- 26 • 2002 Customer Based-Generation Call
- 27 • 2006 Open Call for Power
- 28 • 2009 Bioenergy Phase 1 Call

- 1 • 2010 community-Based Biomass Call
- 2 • 2011 Bioenergy Phase 2 Call
- 3 • Standing Offer Program up to 15 MW
- 4 • 2009-2012 Integrated Power Offer

5 Based on feedback received during the development of the Net Metering Evaluation
6 Report No. 3 posted at <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/net-metering/net-metering-evaluation-report-april2013.pdf>, coupled with BC Hydro's
7
8 review of our current DG processes, BC Hydro has identified gaps between its
9 existing processes and developed an approach on how to bridge those gaps with a
10 seamless suite of offers that span demand-side and supply-side opportunities.
11

12 Next steps include increasing the Net Metering cap from 50 kW to 100 kW for
13 commercial, institutional, industrial, municipal and First Nation customers; provided
14 there will be no adverse cost impacts on non-participating ratepayers; and begin the
15 design of a streamlined acquisition process that supports small-scale DG projects
16 (50 kW to 1 MW) under the umbrella of the Standing Offer Program.

17 *Benefits of Distributed Generation*

18 From the customer's viewpoint, DG may offer energy independence, new choices of
19 electricity supply, enhanced power reliability and improved quality.

20 For utilities, DG may offer benefits such as the potential to avoid transmission and
21 distribution system upgrade costs, reduced line losses, and the freeing up of system
22 capacity to address non-distributed load growth.

23 On a provincial scale, DG may contribute to self-sufficiency, encourage diversity in
24 sectors such as forestry and agriculture, create efficiencies with commercial,
25 industrial, municipal and residential customers, and advance near commercial and
26 emerging technologies and applications with customers.

1 **5.2.18.2 Methodology**

2 Same as 2010 ROR, for the purposes of the 2013 ROR Update, DG potential is not
3 presented as a separate resource option. DG potential is captured within the
4 demand-side management potential and the supply-side resource options, as
5 presented in sections 4 and 5 of the report.

6 **5.2.19 Other Capacity Options**

7 The Canadian Entitlement is the Canadian portion of the potential for additional
8 electricity produced in the Columbia River in the western U.S. as a result of the
9 Columbia River Treaty ratified in 1964. The Province owns the Canadian Entitlement
10 and Powerex markets the energy under an agreement with the Province. While the
11 Province receives the financial benefits of the Canadian Entitlement, BC Hydro has
12 access to the physical product (energy and capacity) and can use it as a source of
13 limited supply. As this supply is not “solely from electricity facilities within the
14 Province”, given the self-sufficiency requirement in the *CEA*, the Canadian
15 Entitlement is not a source of dependable capacity in the long term, and therefore,
16 the role of the Canadian Entitlement is limited as a bridging or contingency resource
17 option.

18 **5.2.20 Nuclear**

19 Nuclear has not been included in the 2013 ROR Update as Policy Action No. 23 of
20 the B.C. Government’s 2007 BC Energy Plan provides that the B.C. Government
21 “rejects nuclear power as a strategy to meet British Columbia’s energy needs”. This
22 is reiterated in B.C. *CEA*, which specifies the objective of not using nuclear power.

23 **5.2.21 Generation Resource Potential Results Summary**

24 The inventory of potential supply-side resource options at the POI is summarized by
25 transmission region in [Table 5-19](#).

Table 5-19 Inventory of Supply-Side Generation Resource Potential by Transmission Region

| Resource Type | Transmission Regions | | | | | | | | | | | | | Total |
|---|----------------------|-------------|------------------|--------------|-------|-------------------------|------------------|----------------|---------|---------------|--|--|---------|-------|
| | Peace River | North Coast | Central Interior | Kelly Nicola | Mica | Revelstoke Ashton Creek | Vancouver Island | Lower Mainland | Selkirk | East Kootenay | | | | |
| Woodbased Biomass | DGC (MW) | 102 | 259 | 41 | 60 | - | - | 335 | 66 | 28 | | | 1,226 | |
| | Firm Egy. (GWh/yr) | 815 | 2,063 | 325 | 476 | - | - | 2,669 | 530 | 225 | | | 9,772 | |
| Biogas Biomass | DGC (MW) | - | - | 2 | 4 | - | - | 2 | 4 | 4 | | | 16 | |
| | Firm Egy. (GWh/yr) | - | - | 17 | 33 | - | - | 19 | 32 | 33 | | | 134 | |
| MSW Biomass | DGC (MW) | - | - | - | - | - | - | - | - | - | | | - | |
| | Firm Egy. (GWh/yr) | - | - | - | - | - | - | - | - | - | | | - | |
| Onshore Wind | DGC (MW) | 1,525 | 1,062 | 273 | 874 | 167 | 289 | 23 | 22 | 36 | | | 4,271 | |
| | Firm Egy. (GWh/yr) | 18,083 | 11,400 | 2,660 | 8,437 | 1,674 | 3,143 | 249 | 194 | 324 | | | 46,165 | |
| Offshore Wind | DGC (MW) | - | 3,203 | - | - | - | - | - | - | - | | | 3,819 | |
| | Firm Egy. (GWh/yr) | - | 47,397 | - | - | - | - | - | - | - | | | 56,700 | |
| Geothermal | DGC (MW) | 20 | 270 | - | 20 | - | 20 | 320 | 60 | - | | | 780 | |
| | Firm Egy. (GWh/yr) | 140 | 2,111 | - | 140 | - | 140 | 2,505 | 420 | - | | | 5,992 | |
| Run of River | DGC (MW) | - | 226 | 43 | 31 | 32 | 32 | 310 | 13 | 41 | | | 1,149 | |
| | Firm Egy. (GWh/yr) | - | 5,786 | 1,597 | 1,809 | 1,928 | 1,648 | 4,802 | 835 | 1,861 | | | 24,543 | |
| Pumped Storage | DGC (MW) | - | 37,000 | - | 4,000 | 465 | - | 79,000 | - | - | | | 225,465 | |
| | Firm Egy. (GWh/yr) | - | - | - | - | - | - | - | - | - | | | - | |
| Site C | DGC (MW) | 1,100 | - | - | - | - | - | - | - | - | | | 1,100 | |
| | Firm Egy. (GWh/yr) | 4,700 | - | - | - | - | - | - | - | - | | | 4,700 | |
| Resource Smart (Rev 6) | DGC (MW) | - | - | - | - | - | 488 | - | - | - | | | 488 | |
| | Firm Egy. (GWh/yr) | - | - | - | - | - | 26 | - | - | - | | | 26 | |
| Natural Gas-fired | DGC (MW) | - | - | - | 862 | - | - | 101 | - | - | | | 973 | |
| | Firm Egy. (GWh/yr) | - | - | - | 6,177 | - | - | 159 | - | - | | | 6,416 | |
| Coal-Fired with CCS | DGC (MW) | 556 | - | - | - | - | - | - | - | - | | | 556 | |
| | Firm Egy. (GWh/yr) | 3,896 | - | - | - | - | - | - | - | - | | | 3,896 | |
| Wave | DGC (MW) | - | 34 | - | - | - | - | 225 | - | - | | | 259 | |
| | Firm Egy. (GWh/yr) | - | 418 | - | - | - | - | 2,088 | - | - | | | 2,506 | |
| Tidal | DGC (MW) | - | - | - | - | - | - | - | - | - | | | 247 | |
| | Firm Egy. (GWh/yr) | - | - | - | - | - | - | - | - | - | | | 1,426 | |
| Solar | DGC (MW) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | | 12 | |
| | Firm Egy. (GWh/yr) | 6 | 5 | 6 | 6 | 6 | 6 | 6 | 5 | 6 | | | 57 | |
| Total Dependable Capacity and ELCC (MW) | 3,306 | 42,056 | 359 | 5,852 | 498 | 708 | 81,317 | 106,028 | 180 | 106 | | | 240,410 | |
| Total Firm Energy (GWh/yr) | 27,728 | 69,180 | 4,604 | 17,079 | 1,934 | 3,495 | 24,250 | 9,941 | 2,130 | 2,416 | | | 162,756 | |

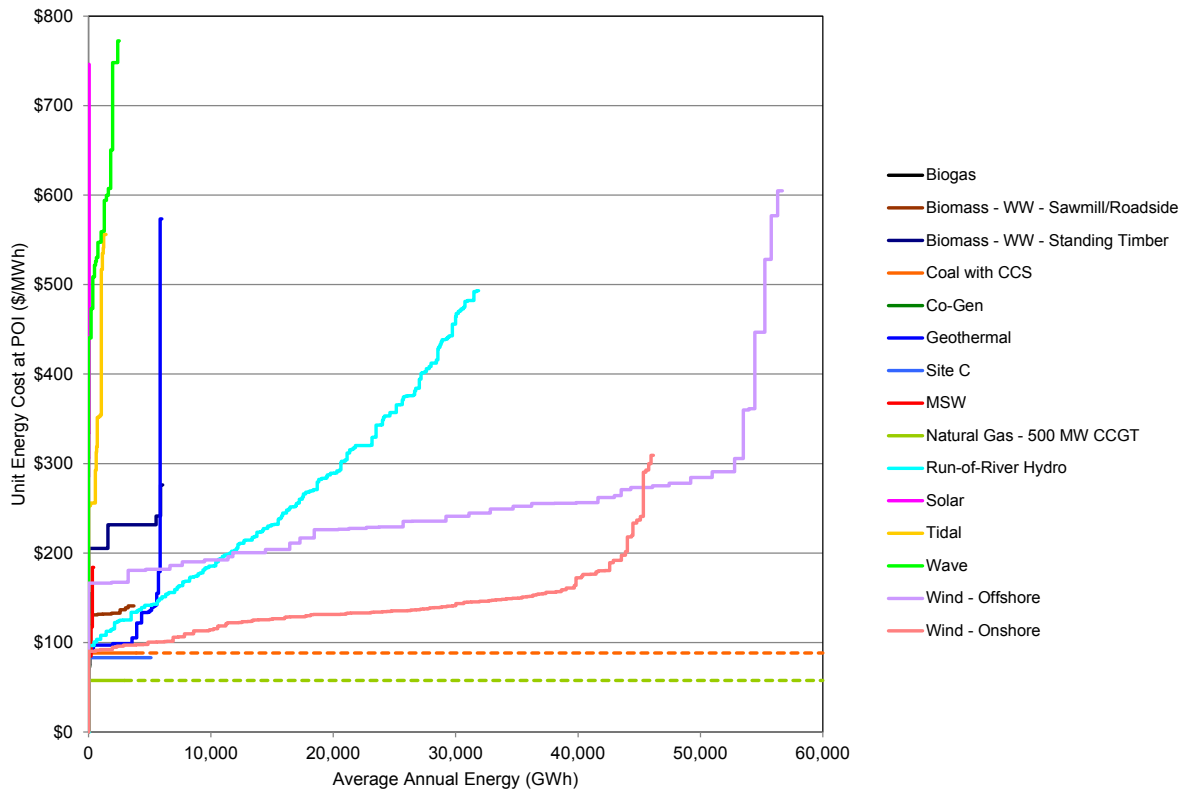
Notes: 1. The RoR values represent the potentials with UEC under \$500/MWh.
 2. Site C data presented in this table is based on information provided in the Site C EIS submission filed in January 2013.
 3. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options.

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1 In order to facilitate a high-level comparison of costs for the inventory of generation
 2 resource potential, [Figure 5-23](#) provides an overview of the base UECs at POI.

3 **Figure 5-23 Supply-Side Generation Resource**
 4 **Potential Supply Curve Summary – Base**
 5 **UECs \$/MWh at POI**



6 Notes:

- 7 1. Representative projects were used to characterize the natural gas-fired and coal-fired resource options.
- 8 Dotted lines indicate additional potential.
- 9 2. The Site C values presented in this figure are based on information provided in the Site C EIS submission
- 10 filed in January 2013.
- 11 3. The run-of-river results shown above have been summarized for resources with a UEC under \$500/MWh.

12 A more detailed overview of base UECs at POI under \$200/MWh, and a summary of
 13 the uncertainties associated with the data are presented in [Table 5-20](#).

Table 5-20 Supply-Side Generation Resource Potential – UEC Values at POI below \$200/MWh

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------------|----------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Biogas | Bailey | LM | 12 | 59 | Pre-feasibility | Medium | High |
| Biogas | Comox Valley | VI | 8 | 69 | Pre-feasibility | Medium | High |
| Biogas | Foothills Blvd | CI | 17 | 70 | Pre-feasibility | Medium | High |
| Biogas | Minnie's Pit | LM | 7 | 70 | Pre-feasibility | Medium | High |
| Biogas | Cache Creek | KL | 27 | 73 | Pre-feasibility | Medium | High |
| Biogas | Glenmore | SL | 18 | 73 | Pre-feasibility | Medium | High |
| Biogas | Alberni valley | VI | 7 | 75 | Pre-feasibility | Medium | High |
| Biogas | Greater Vernon | SL | 7 | 91 | Pre-feasibility | Medium | High |
| Biogas | Campbell Mtn | SL | 7 | 95 | Pre-feasibility | Medium | High |
| Biogas | Ecowaste | LM | 13 | 96 | Pre-feasibility | Medium | High |
| Biogas | Mission Flats | KL | 6 | 106 | Pre-feasibility | Medium | High |
| Biogas | Campbell River | VI | 4 | 154 | Pre-feasibility | Medium | High |
| Biomass WW - RSD/SMW | WBBio_WPR | NC | 97 | 122 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_EPR | NC | 98 | 123 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_WK | SL | 530 | 131 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_SP | PR | 446 | 132 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_VI | VI | 707 | 132 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_LM | LM | 707 | 133 | Survey | Medium | Medium |

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| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|--------------------------------|---|---------------------|-----------------------------|----------------------------|----------------|---------------------------|------------------|
| Biomass WW - RSD/SMW | WBBio_MAC | CI | 325 | 137 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_PG | NC | 106 | 137 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_EK | EK | 225 | 139 | Survey | Medium | Medium |
| Biomass WW - RSD/SMW | WBBio_KM | KL | 476 | 141 | Survey | Medium | Medium |
| Coal-fired generation with CCS | 750 MW Integrated Gasification Combined Cycle | PR | 3,896 | 88 | Survey | High | High |
| Co-gen | Small Co-generation projects | LM | 80 | 74 | Survey | Low | Medium |
| Geothermal | Mt. Garibaldi | LM | 394 | 91 | Survey | High | High |
| Geothermal | Mt. Edziza | NC | 1,577 | 97 | Survey | High | High |
| Geothermal | Pebble Creek | LM | 788 | 99 | Survey | High | High |
| Geothermal | South Meager Creek | LM | 788 | 99 | Feasibility | High | High |
| Geothermal | Mt. Cayley | LM | 394 | 105 | Survey | High | High |
| Geothermal | Hoodoo Mountain | NC | 394 | 122 | Survey | High | High |
| Geothermal | Mt. Silverthorne | VI | 394 | 134 | Survey | High | High |
| Geothermal | Kootenay Lake | SL | 140 | 134 | Survey | High | High |
| Geothermal | Hudson's Hope | PR | 140 | 134 | Survey | High | High |
| Geothermal | Lakelse Lake | NC | 140 | 136 | Survey | High | High |
| Geothermal | Harrison Hot Springs | LM | 140 | 139 | Survey | High | High |
| Geothermal | Canoe Creek/Valemont | KL | 140 | 141 | Survey | High | High |
| Geothermal | Upper Arrow Lake | REV | 140 | 142 | Survey | High | High |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------------|-----------------------------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Geothermal | Lower Arrow Lake | SL | 140 | 155 | Survey | High | High |
| Geothermal | Okanagan Valley | SL | 140 | 179 | Survey | High | High |
| Large Hydro - Site C | Site C Clean Energy Project | PR | 5,100 | 83 * | Feasibility | Medium | Medium |
| MSW | MSW2_LM | LM | 211 | 85 | Pre-feasibility | Medium | High |
| MSW | MSW1_VI | VI | 101 | 117 | Pre-feasibility | Medium | High |
| MSW | MSW3_SE | SL | 112 | 184 | Pre-feasibility | Medium | High |
| Natural Gas | 500 MW Combined Cycle Gas Turbine | KL | 2,940 | 58 | Pre-feasibility | Medium | High |
| Natural Gas | 250 MW Combined Cycle Gas Turbine | KL | 1,450 | 62 | Pre-feasibility | Medium | High |
| Natural Gas | 50 MW Combined Cycle Gas Turbine | KL | 300 | 92 | Pre-feasibility | Medium | High |
| Run of River Hydro | ROR_80-100_LM | LM | 224 | 97 | Survey | Low | Medium |
| Run of River Hydro | ROR_90-100_KN | KL | 220 | 97 | Survey | Low | Medium |
| Run of River Hydro | ROR_100-110_KN | KL | 217 | 101 | Survey | Low | Medium |
| Run of River Hydro | ROR_100-110_LM | LM | 329 | 104 | Survey | Low | Medium |
| Run of River Hydro | ROR_100-110_VI | VI | 450 | 108 | Survey | Low | Medium |
| Run of River Hydro | ROR_110-120_VI | VI | 386 | 113 | Survey | Low | Medium |
| Run of River Hydro | ROR_110-120_NC | NC | 135 | 115 | Survey | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|--------------------|-----------------|---------------------|-----------------------------|----------------------------|----------------|---------------------------|------------------|
| Run of River Hydro | ROR_110-120_BQL | NC | 158 | 115 | Survey | Low | Medium |
| Run of River Hydro | ROR_110-130_KN | KL | 173 | 122 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-130_MCA | MCA | 104 | 123 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-130_EK | EK | 147 | 124 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-130_VI | VI | 116 | 125 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-130_SE | SL | 88 | 125 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-140_NC | NC | 90 | 125 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-130_LM | LM | 649 | 125 | Survey | Low | Medium |
| Run of River Hydro | ROR_130-140_VI | VI | 492 | 134 | Survey | Low | Medium |
| Run of River Hydro | ROR_120-140_REV | REV | 131 | 136 | Survey | Low | Medium |
| Run of River Hydro | ROR_130-140_LM | LM | 206 | 137 | Survey | Low | Medium |
| Run of River Hydro | ROR_130-150_EK | EK | 94 | 139 | Survey | Low | Medium |
| Run of River Hydro | ROR_130-150_SE | SL | 189 | 139 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-150_VI | VI | 558 | 142 | Survey | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|--------------------|-----------------|---------------------|-----------------------------|----------------------------|----------------|---------------------------|------------------|
| Run of River Hydro | ROR_130-150_KN | KL | 117 | 142 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-150_LM | LM | 326 | 143 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-160_MCA | MCA | 35 | 145 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-150_REV | REV | 149 | 147 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-160_BQL | NC | 199 | 149 | Survey | Low | Medium |
| Run of River Hydro | ROR_140-160_NC | NC | 319 | 151 | Survey | Low | Medium |
| Run of River Hydro | ROR_150-170_EK | EK | 193 | 154 | Survey | Low | Medium |
| Run of River Hydro | ROR_150-160_REV | REV | 75 | 155 | Survey | Low | Medium |
| Run of River Hydro | ROR_150-160_LM | LM | 461 | 156 | Survey | Low | Medium |
| Run of River Hydro | ROR_150-170_SE | SL | 218 | 159 | Survey | Low | Medium |
| Run of River Hydro | ROR_150-170_KN | KL | 131 | 162 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-170_LM | LM | 325 | 164 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-170_CI | CI | 167 | 168 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-170_VI | VI | 374 | 168 | Survey | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|--------------------|-----------------|---------------------|-----------------------------|----------------------------|----------------|---------------------------|------------------|
| Run of River Hydro | ROR_170-180_CI | CI | 49 | 172 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-180_LM | LM | 295 | 173 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-180_NC | NC | 90 | 174 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-180_REV | REV | 142 | 174 | Survey | Low | Medium |
| Run of River Hydro | ROR_160-180_MCA | MCA | 134 | 174 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-190_KN | KL | 158 | 177 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-180_VI | VI | 232 | 178 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-190_BQL | NC | 154 | 181 | Survey | Low | Medium |
| Run of River Hydro | ROR_180-190_CI | CI | 156 | 183 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-190_SE | SL | 68 | 184 | Survey | Low | Medium |
| Run of River Hydro | ROR_170-190_EK | EK | 111 | 184 | Survey | Low | Medium |
| Run of River Hydro | ROR_180-190_LM | LM | 401 | 185 | Survey | Low | Medium |
| Run of River Hydro | ROR_180-200_NC | NC | 166 | 186 | Survey | Low | Medium |
| Run of River Hydro | ROR_180-200_REV | REV | 195 | 190 | Survey | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|--------------------|-----------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Run of River Hydro | ROR_180-200_MCA | MCA | 162 | 193 | Survey | Low | Medium |
| Run of River Hydro | ROR_180-200_VI | VI | 168 | 194 | Survey | Low | Medium |
| Run of River Hydro | ROR_190-200_BQL | NC | 174 | 196 | Survey | Low | Medium |
| Run of River Hydro | ROR_190-210_KN | KL | 168 | 198 | Survey | Low | Medium |
| Run of River Hydro | ROR_190-210_LM | LM | 264 | 199 | Survey | Low | Medium |
| Run of River Hydro | ROR_190-210_SE | SL | 143 | 200 | Survey | Low | Medium |
| Wind - Offshore | Wind_OBC24-1 | VI | 1892 | 166 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC25-1 | VI | 1347 | 167 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC28 | VI | 1442 | 181 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC8-1 | NC | 1967 | 182 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC29 | VI | 1014 | 186 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC7-1 | NC | 1812 | 190 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC14-1 | NC | 1911 | 192 | Pre-feasibility | Medium | High |
| Wind - Offshore | Wind_OBC3 | NC | 403 | 196 | Pre-feasibility | Medium | High |
| Wind - Onshore | Wind_PC28 | PR | 591 | 90 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC21 | PR | 371 | 92 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC19 | PR | 441 | 92 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC13 | PR | 541 | 92 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC16 | PR | 377 | 95 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC14 | PR | 527 | 96 | Pre-feasibility | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------|--------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Wind - Onshore | Wind_PC10 | PR | 1,023 | 97 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC20 | PR | 609 | 98 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC15 | PR | 382 | 98 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC09 | PR | 713 | 100 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC11 | PR | 473 | 101 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC41 | PR | 155 | 101 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC42 | PR | 219 | 101 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC18 | PR | 486 | 101 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC26 | PR | 416 | 106 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC48 | PR | 505 | 106 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC06 | PR | 761 | 110 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC09 | NC | 1,025 | 113 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI12 | VI | 151 | 113 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI14 | VI | 113 | 113 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC27 | PR | 333 | 114 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC40 | PR | 350 | 115 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI13 | VI | 105 | 118 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI12 | REV | 545 | 119 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI15 | VI | 126 | 121 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC05 | PR | 353 | 122 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI23 | KL | 569 | 122 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC10 | CI | 280 | 122 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC25 | CI | 450 | 123 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC12 | PR | 308 | 123 | Pre-feasibility | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------|--------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Wind - Onshore | Wind_SI20 | KL | 122 | 124 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC17 | PR | 315 | 125 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC43 | PR | 139 | 125 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC47 | PR | 108 | 125 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI15 | KL | 814 | 126 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC37 | PR | 231 | 126 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC20 | NC | 294 | 127 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC22 | NC | 697 | 127 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI08 | VI | 113 | 128 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC04 | PR | 349 | 128 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC34 | PR | 906 | 129 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC07 | NC | 322 | 129 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI22 | KL | 126 | 130 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI10 | KL | 313 | 130 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI14 | REV | 232 | 131 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI07 | VI | 502 | 131 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC01 | NC | 1729 | 132 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC18 | NC | 426 | 132 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI19 | KL | 148 | 133 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI04 | KL | 253 | 133 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI16 | KL | 1632 | 133 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC12 | NC | 230 | 134 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI05 | VI | 703 | 134 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC32 | PR | 368 | 134 | Pre-feasibility | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------|--------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Wind - Onshore | Wind_SI18 | KL | 335 | 135 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI32 | SL | 89 | 135 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC21 | NC | 589 | 135 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC02 | NC | 666 | 136 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC19 | NC | 279 | 136 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC36 | PR | 425 | 136 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI05 | KL | 355 | 137 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI27 | LM | 249 | 137 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC38 | PR | 330 | 138 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI37 | EK | 87 | 138 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC44 | PR | 105 | 138 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI11 | REV | 330 | 139 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC01 | PR | 455 | 139 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC11 | CI | 195 | 139 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC25 | CI | 426 | 140 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC08 | NC | 463 | 141 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI28 | KL | 261 | 141 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI13 | REV | 567 | 143 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI10 | VI | 89 | 144 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC23 | NC | 278 | 145 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI11 | VI | 112 | 145 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC03 | PR | 222 | 145 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI03 | KL | 355 | 145 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC07 | PR | 325 | 145 | Pre-feasibility | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------|--------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Wind - Onshore | Wind_SI01 | KL | 553 | 146 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC29 | PR | 201 | 146 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI38 | EK | 237 | 147 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI06 | VI | 333 | 147 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI02 | VI | 467 | 148 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI30 | KL | 396 | 148 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC08 | NC | 490 | 149 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC13 | NC | 481 | 150 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI29 | KL | 314 | 150 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC26 | KL | 376 | 151 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI09 | KL | 212 | 151 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI06 | KL | 294 | 152 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC24 | CI | 285 | 153 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC23 | CI | 150 | 154 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC02 | PR | 371 | 154 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI08 | KL | 256 | 155 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC17 | PR | 824 | 156 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC09 | NC | 438 | 157 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC08 | PR | 130 | 159 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI26 | KL | 263 | 159 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI31 | KL | 340 | 161 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC24 | CI | 321 | 161 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_SI02 | KL | 151 | 164 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_PC22 | CI | 442 | 172 | Pre-feasibility | Low | Medium |

| Resource Type | Project Name | Transmission Region | Average Annual Energy (GWh) | UEC @ 7% Real (\$2013/MWh) | Level of Study | Resource Type Uncertainty | Cost Uncertainty |
|----------------|--------------|---------------------|-----------------------------|----------------------------|-----------------|---------------------------|------------------|
| Wind - Onshore | Wind_PC45 | CI | 111 | 174 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC15 | PR | 623 | 176 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC10 | NC | 458 | 176 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_VI04 | VI | 178 | 179 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC06 | NC | 554 | 180 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC11 | NC | 386 | 181 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC12 | NC | 290 | 189 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_NC05 | NC | 660 | 192 | Pre-feasibility | Low | Medium |
| Wind - Onshore | Wind_BC07 | PR | 333 | 198 | Pre-feasibility | Low | Medium |

Notes:

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1. Resource options presented alphabetically and values rounded to the nearest integer.
 2. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options.
 3. UECs for natural gas-fired options are based on natural gas price estimates from BC Hydro's 2013 Market Scenario 1.
 4. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013, and the UEC is calculated assuming 5 per cent real cost of capital.
 5. For presentation purposes, the bundling results have been limited to results below \$200/MWh.

1 The inventory of energy resource potential, by resource type, is summarized in
 2 [Table 5-21](#) as follows:

3 **Table 5-21 Summary of Supply-Side Energy**
 4 **Resource Potential by Resource Type –**
 5 **UEC Values at POI**

| Energy Resource | Total Annual Energy (GWh/year) | Total Dependable Generation Capacity (MW) | UEC @ 7% real cost of capital, at POI (\$2013/MWh) |
|-----------------------|--------------------------------|---|--|
| Biomass – Wood Based | 9,772 | 1,226 | 122 – 276 |
| Biomass – Biogas | 134 | 16 | 59 – 154 |
| Biomass – MSW | 425 | 50 | 85 – 184 |
| Wind – Onshore | 46,165 | 4,271 | 90 – 309 |
| Wind – Offshore | 56,700 | 3,819 | 166 – 605 |
| Geothermal | 5,992 | 780 | 91 – 573 |
| Run-of-river | 31,880 | 1,149 | 93 – 500 |
| Large Hydro - Site C | 5,100 | 1,100 | 83 * |
| CCGT and Cogeneration | 4,770 | 774 | 60 – 94 |
| Coal with CCS | 3,896 | 556 | 88 |
| Wave | 2,506 | 259 | 440 – 772 |
| Tidal | 1,426 | 247 | 253 – 556 |
| Solar | 57 | 12 | 266 – 746 |

6 Notes:

- 7 1. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource
 8 options.
 9 2. The Site C values presented in this table are based on information provided in the Site C EIS submission filed
 10 in January 2013 using estimates of annual energy of 5,100 GWh/year, dependable capacity of 1,100 MW and
 11 base UEC (at 5 per cent real) at POI of \$80/MWh in 2011\$ based on capital cost of \$7.9 billion.
 12 3. The run-of-river results shown above have been summarized for resources with a UEC under \$500/MWh.

13 The supply-side capacity options inventory is summarized in [Table 5-22](#) as follows:

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**Table 5-22 Summary of Supply-Side Capacity
Resource Potential – UCC at POI
Summary**

| Resource Type | Capacity Option | Transmission Region | Dependable Capacity (MW) | UCC @ 7% real cost of capital, at POI (\$2013/kW-year) |
|------------------------------|-----------------------------------|---------------------|--------------------------|--|
| Resource Smart | GMS Units 1-5 Capacity Increase | PR | 220 | 35 * |
| Resource Smart | Revelstoke Unit 6 | REV | 488 | 50 * |
| Natural Gas-fired Generation | SCGT at Kelly/Nicola | KL | 98 | 84 |
| Pumped Storage | PS at Mica Generating Station | MCA | 465 | 100 * |
| Pumped Storage | Kenyon – Stave | LM | 1,000 | 118 |
| Pumped Storage | Upper Deserted - Un-named | LM | 1,000 | 118 |
| Pumped Storage | Upper Vancouver - Lower Vancouver | LM | 1,000 | 120 |
| Pumped Storage | Upper Vancouver - Lower Misery | LM | 1,000 | 120 |
| Pumped Storage | Haynon - Chochiwa | KL | 1,000 | 121 |
| Pumped Storage | Burwell - Seymour | LM | 1,000 | 121 |
| Pumped Storage | Blinch – Stave | LM | 1,000 | 122 |
| Pumped Storage | Palisade - Seymour | LM | 1,000 | 124 |

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Notes:

1. GMS Units 1-5 Capacity Increase numbers are based on conceptual level estimates.
2. SCGT and Pumped Storage only include fixed costs.
3. UCCs for GMS Units 1-5 Capacity Increase, Revelstoke Unit 6, and PS at Mica Generating Station are calculated assuming 5 per cent real cost of capital.
4. A SCGT representative project is used to characterize the Natural Gas resource option.
5. Presentation of PS data is limited to results below \$125/kW-year.

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As discussed in section [5.2.19](#), BC Hydro also has access to the capacity associated with the CE and this capacity is relied upon as a contingency resource, not a long-term planning option.

5.3 Bulk Transmission Resource Options

To be able to serve customers with electricity, BC Hydro must both connect the generation resources to the electric system and deliver that electricity to customers through the transmission system. In addition, the B.C. CEA requires that BC Hydro identify long-term transmission requirements in the long-term system resource planning process.

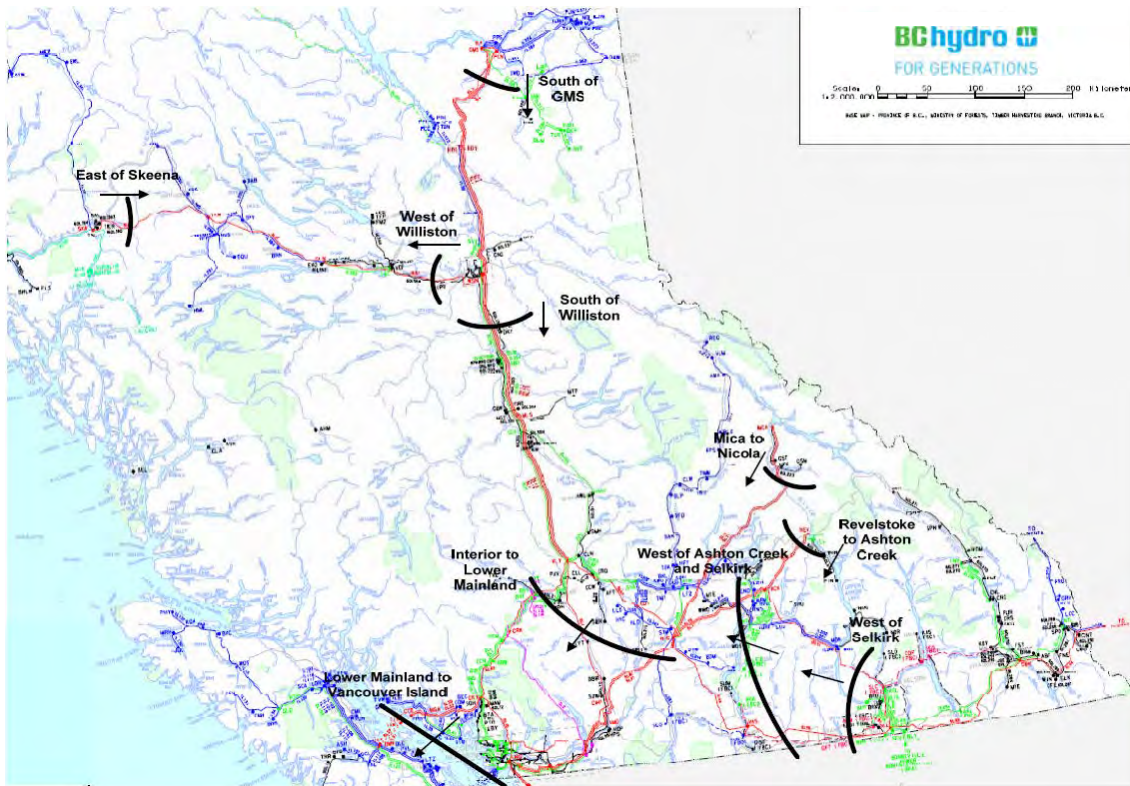
To achieve this mandate BC Hydro has reviewed the transmission options required to remove congestion from various sections of BC Hydro's bulk transmission network. In the next section, transmission congestion is described and existing transmission limits are specified. Following that, a list of options for addressing congestion is provided.

5.3.1 Transmission Paths, Cut-Planes, and Congestion

[Figure 5-24](#) provides an overview of the BC Hydro's transmission system, paths and cut-planes. A transmission path consists of one or several transmission lines which transfer power between two regions. Cut-planes are imaginary lines that cut through one or more transmission paths to identify transmission bottlenecks of an integrated network. When the expected flow on a cut-plane exceeds its thermal, voltage stability, or transient stability limits, the cut-plane is constrained and requires incremental capacity. In this diagram the red lines indicate the existing 500 kV transmission lines, the green lines indicate the 230 kV transmission lines, the blue lines indicate the 138 kV transmission lines and the black lines cutting across the red transmission lines are the cut-planes indicating the areas of congestion for which the basket of transmission resource options were identified. The direction of the arrows indicates the typical direction of power flow, i.e., the transfer of power from the supply side of the cut-plane towards its load side.

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Figure 5-24 Overview of Transmission System and Cut-Planes



3 [Table 5-23](#) outlines total transfer capability (TTC) and the limiting constraint for each
4 one of the BC Hydro's bulk transmission cut-planes.

1

Table 5-23 Cut-Plane Capacities

| No. | Cut-plane | TTC (MW) 2010/2011 | Limiting Load Condition | Limiting Constraint |
|-----|---------------------------------------|-----------------------|----------------------------|---------------------|
| 1 | South of GMS | 3590 | Heavy Winter | Voltage Stability |
| | | 3620 | Light Winter | Voltage Stability |
| 2 | South of Williston | 3060 | Heavy Winter | Voltage Stability |
| | | 3340 | Light Winter | Voltage Stability |
| 3 | East of Skeena | 1000 | Light Summer | Transient Stability |
| 4 | West of Williston | 695 | Heavy Winter | Voltage Stability |
| 5 | West of Selkirk | 1910 | Heavy Winter | Voltage Stability |
| | | 2320 | Heavy Summer | Voltage Stability |
| 6 | West of Ashton Creek/Selkirk | 3270 | Heavy Winter | Voltage Stability |
| | | 4020 | Heavy Summer | Voltage Stability |
| 7 | Mica to Nicola | 1650 | All Seasons | Voltage Stability |
| 8 | Revelstoke to Ashton Creek | 3000 | Winter | Thermal Limits |
| | | 2060 | Summer | Thermal Limits |
| 9 | Interior to Lower Mainland | ~ 5000 | All Seasons | Thermal Limits |
| 10 | Lower Mainland to Vancouver Island | 2000 | Winter | Thermal Limits |
| | | 1900 | Summer | Thermal Limits |

2 **5.3.2 Bulk Transmission Options**

3 [Table 5-24](#) identifies transmission options that BC Hydro is considering over a
4 30-year transmission resource planning horizon. In this table, each transmission
5 option includes a brief description, a construction lead time, a direct capital cost, an
6 expected added capacity and the applicable line length. Some transmission
7 reinforcements enhance transfer capacity of more than one transmission cut-plane.
8 For these transmission options, all impacted cut-planes and their respective
9 incremental transmission capacities are identified. All cost estimates are in 2013
10 dollars and do not include overhead and interest during construction.

11 [Table 5-24](#) also includes transmission projects which are at various phases of their
12 completion. These projects include new Nicola – Meridian 500 kV line 5L83 and
13 series compensation of 500 kV circuits 5L71 and 5L72. Both of these projects will be
14 modelled in future resource planning load/resource scenarios at their respective
15 ISDs. [Table 5-24](#) is not inclusive of all possible solutions but captures the ones that

1 have been previously reviewed. In the analysis phase of the resource planning
 2 process, BC Hydro intends to remove potential bulk transmission constraints by
 3 modeling the incremental transfer capacities that appropriate transmission options
 4 provide.

5 Scope, schedule, and cost of the listed transmission options are approximate. More
 6 accurate information would be prepared as a particular option becomes necessary.

7 **Table 5-24 Transmission Reinforcement Options**
 8 **Considered in Long-Term Resource**
 9 **Planning**

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$Million) | Incremental Capacity (MW) | Line Length (km) |
|-----------------------|--|--------------------------|-------------------------------------|----------------------------------|-------------------------|
| North Interior | | | | | |
| TO-01 | New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston. | 8 | 388.3 | 1470 | 278 |
| TO-02 | New 500 kV, 50 per cent series compensated transmission circuit 5L14 between Williston and Kelly Lake. | 8 | 341.1 | 2120 | 330 |
| TO-03 | New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1. | 8 | 1,482.9 | 1000 | 928 |
| TO-04 | New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2. | 8 | 246.8 | 1000 | N/A |
| TO-05 | Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating. | 3 | 59.5 | 360 (CI-KLY/NIC) and 300 (PR-CI) | N/A |
| TO-06 | Series compensation upgrade at McLeese from 50 per cent to 65 per cent on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating. | 3 | 57.2 | 390 (CI-KLY/NIC) and 330 (PR-CI) | N/A |

Integrated Resource Plan Appendix 3A-1

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$Million) | Incremental Capacity (MW) | Line Length (km) |
|-----------------------|--|--------------------------|-------------------------------------|---|-------------------------|
| TO-07 | 500 kV Shunt compensation: At Williston add one 300 MVar SVC and two 250 MVar switchable capacitor banks. At Kelly Lake add one 250 MVar shunt capacitor. | 3 | 65.1 | 650 (CI-KLY/NIC) and 580 (PR-CI) | N/A |
| North Coast | | | | | |
| TO-08 | New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing 5L61 - 5L62 and 5L63 lines. | 8 | 1,031.6 | 970 | 449 |
| TO-09 | Series compensation of the WSN-SKA 500 kV lines 5L61, 5L62 and 5L63 plus voltage support and transformation addition in the existing BC Hydro substations. | 3 | 142.3 | 580 | N/A |
| TO-21 | A new +/-500 kV HVDC bipole transmission circuit between WSN and SKA. | 8 | 1,091.6 | 2000 | 449 |
| South Interior | | | | | |
| TO-10 | New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake. | 8 | 226.7 | 750 | 163 |
| TO-11 | New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola. | 8 | 196.3 | 750 | 138 |
| TO-12 | 50 per cent series compensation of the 500 kV lines 5L91 and 5L98. | 3 | 61.8 | 133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK) | N/A |
| TO-13 | 50 per cent series compensation of 500 kV lines 5L71 and 5L72. | Committed in 2014 | 46.0 | 950 | N/A |
| TO-14 | 50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96. | 3 | 60.3 | 112 | N/A |
| TO-19 | 50 per cent Series compensation of 500 kV line 5L92 SEL-CBK. | 3 | 31.2 | 150 | N/A |

| Item No. | Upgrade Option Description | Lead Time (Years) | 2013 Direct Cost (\$Million) | Incremental Capacity (MW) | Line Length (km) |
|---|---|--------------------------|-------------------------------------|----------------------------------|-------------------------|
| TO-20 | A new 500 kV line between Selkirk and Cranbrook parallel to the existing 500 kV line 5L92. | 8 | 651.1 | 1550 | 180 |
| Interior to Lower Mainland | | | | | |
| TO-15 | New 500 kV, 50 per cent series compensated transmission circuit 5L83 between Nicola and Meridian. | Committed in 2015 | 609.2 | 1550 | 247 |
| TO-16 | New 500 kV, 50 per cent series compensated transmission circuit 5L46 between Kelly Lake and Cheekye. | 8 | 656.7 | 1384 | 197 |
| TO-17 | 500 kV and 230 kV shunt compensation: At Meridian 230 kV add two 110 MVar capacitor banks At Nicola 500 kV add one 250 MVar capacitor bank. | 3 | 10.1 | 570 | N/A |
| Lower Mainland to Vancouver Island | | | | | |
| TO-18 | New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal. | 6 | 230.1 | 600 | 67 |

1 Note: TO-15 presented in this table is based on information filed with BCUC in November 2011.

2 **5.3.3 Transmission Expansion Projects**

3 Not all BC Hydro transmission projects are driven by the elimination of transmission
4 congestion. Some of the ongoing and under review projects are to expand the
5 existing network to supply electricity to remote communities, to benefit from potential
6 resources in the remote areas, and to improve trade opportunities.

7 BC Hydro’s transmission planning process includes one transmission expansion
8 project known as the Northwest Transmission Line (NTL). The NTL is a 344 km,
9 287 kV circuit from Skeena substation (near Terrace) to a new substation to be built
10 near Bob Quinn Lake. It is designed to provide power to remote northwest parts of
11 the province and to facilitate connection of new generation resources to the grid. The
12 expected ISD for this project is spring 2014.

1 The Northeast Transmission Line (**NETL**) is an example of the current transmission
2 expansion studies. In the NETL studies, BC Hydro assessed supply of significant
3 load growth in the Fort Nelson and the Horn River Basin (**HRB**) regions, driven by
4 prospects for natural gas production-related activities. The studies are based on
5 forecasts for natural gas production and associated raw gas treatment and gas
6 processing facilities, resulting in an electricity demand in the range of 350 MW to
7 1100 MW.

8 The studies looked at interconnecting the Fort Nelson/HRB regions to the BC Hydro
9 integrated system, through a new 550 km transmission interconnection running from
10 GMS to Fort Nelson/HRB. Given the distances and the wide range of load
11 expectations, the voltages examined were 230 kV and 500 kV. A 500-kV
12 transmission interconnection would facilitate integration of up to 1500 MW of wind
13 power projects in the Hackney Hills area (about 100 km north of GMS), as well as up
14 to 300 MW of natural gas production-related and other loads in the same vicinity.

15 The studies also examined supplying load growth in the Fort Nelson/HRB regions
16 through local gas-fired generation using a variety of gas turbine technologies and
17 configurations. Co-generation alternatives, involving production of both electricity
18 and heat (steam) for gas processing purposes were included.

19 **5.3.4 Regional Transmission Projects**

20 The main focus of the integrated resource planning process is to identify major bulk
21 transmission upgrades and transmission facilities required for interconnecting new
22 resources to the grid. As such, the ongoing planning work to accommodate the
23 growing regional demand at sub-transmission and distribution voltages is not
24 covered in this process. Details of regional transmission projects are published
25 through the capital planning process.

26 One example of the regional transmission projects is Dawson Creek / Chetwynd
27 Area Transmission project (**DCAT**). This project, which received a Certificate of
28 Public Convenience and Necessity (**CPCN**) from the BCUC in April 2013, is driven

1 by the rapid load growth in Dawson Creek area and would build a new 60 km,
2 230 kV double circuit from the future Sundance substation (19 km east of Chetwynd)
3 to Bear Mountain Terminal (**BMT**) near Dawson Creek. Another 12 km of 230 kV
4 double circuit transmission lines would connect the expanded Dawson Creek
5 Substation to BMT. The expected project in-service date is June 2015.

6 The conceptual second phase of the DCAT project is known as the Peace Region
7 Electrical Supply (**PRES**) project, previously known as GDAT (GMS to Dawson
8 Creek Area Transmission). This includes BC Hydro's plan for the reliable supply of
9 additional new loads in the South Peace region. DCAT's CPCN is considered a
10 prerequisite for the PRES project.

11 Details of regional transmission projects are published through the capital planning
12 process.

13 **5.3.5 Transmission for Export**

14 BC Hydro is exploring the opportunity to create new transmission capacity between
15 B.C. and power markets in the Mid-C and California. This effort will enable trading of
16 B.C.'s surplus energy. In addition, it will allow BC Hydro, IPPs, and energy traders to
17 have access to the U.S. markets.

18 BC Hydro considers the resource planning process to be an appropriate platform for
19 assessing different levels of power export. It is recognized that the existing
20 transmission congestion along the I-5 corridor on the Pacific North West makes a
21 new transmission path from eastern part of B.C. to Mid-C and California more viable
22 than other options. The Selkirk substation (**SEL**) is viewed as a suitable modeling
23 hub for collecting B.C.'s excess energy and transferring it to the U.S.

24 In modeling, a generic 500 kV single tower transmission path from SEL to Devil's
25 Gap Substation near Spokane in Washington State is considered as the new
26 transmission link between B.C. and U.S. Depending on the level of power transfer to

1 the U.S., the SEL – Devil’s Gap transmission path is configured with one or two
2 500 kV transmission circuit(s).

3 The SEL – Devil’s Gap circuit fits within the scope of a future hybrid transmission
4 path from eastern B.C. to northern California. This transmission path is also known
5 as the Canada-Northwest-California (**CNC**) project. The CNC transfers up to
6 3,000 MW power from B.C.’s renewable resources to Northern California and
7 includes a double circuit 500 kV high-voltage alternating current (**HVAC**) line from
8 SEL to Devil’s Gap Substation to North East Oregon Substation (**NEO**) and a
9 +/-500 kV HVDC bipole from NEO to Collinsville Substation near San Francisco. The
10 CNC partners have abandoned the CNC project for the foreseeable future.

11 Any investment in the expansion of the transmission network for exporting power to
12 the US will depend on a strong demand for importing BC’s clean energy. Until such
13 demand is proven, expansion of the BC’s transmission tie-lines remains conceptual.

14 **5.3.6 Transmission for Interconnecting Individual New Resources**

15 In the resource options review phase of the planning process, the cost of
16 interconnecting individual new resources to the existing transmission grid is
17 estimated. The cost breakdown includes: the cost of the power line, the cost of the
18 new sectionalizing substation for interconnecting the power line to an existing
19 BC Hydro high voltage line¹⁹, and the cost of termination and possible voltage
20 transformation at an existing BC Hydro substation.

21 To assess the cost of the power line, transmission voltage level needs to be known.
22 For each new generation resource the transmission voltage level is determined
23 based on the rated output of generating plant and its distance from the nearest
24 BC Hydro transmission facility. [Table 5-25](#) provides the estimated per kilometre cost
25 of overhead lines and submarine cables. [Table 5-26](#) and [Table 5-27](#) are generic
26 estimates of interconnecting substation cost and transformation cost in 2011 dollars.

¹⁹ In the Resource Options phase of the IRP process, a new substation is considered only for interconnecting 25 kV, 69 kV, 138 kV, 230 kV and 287 kV power lines to the existing lines with similar voltages.

1 **Table 5-25 Unit Cost of Power Lines**

| New Power Line Voltage (kV) | Cost (\$/km), \$2011 | | | |
|-----------------------------|---|--|--|-----------------|
| | Average Overhead Line Slope (0-15 per cent) | Average Overhead Line Slope (16-30 per cent) | Average Overhead Line Slope (>30 per cent) | Submarine Cable |
| 25 | 84,800 | 169,600 | 254,400 | 500,000 |
| 69 | 106,000 | 212,000 | 318,000 | 1,000,000 |
| 138 | 159,000 | 318,000 | 477,000 | 3,600,000 |
| 230 | 265,000 | 530,000 | 795,000 | 5,300,000 |
| 500 | 530,000 | 1,060,000 | 1,590,000 | 7,100,000 |

2 **Table 5-26 Interconnection Substation Cost**

| New Power Line Voltage (kV) | Interconnecting Substation Cost (\$2011, millions) |
|-----------------------------|--|
| 25 | 1.5 (0.4 for tapping an existing line) |
| 69 | 7.5 |
| 138 | 9.5 |
| 230 (or 287) | 10.5 |

3 **Table 5-27 Voltage Transformation Cost**

| New Generation Power Line Voltage (kV) | Transformation Cost (\$2011, millions) | | | | | | |
|--|--|-----|-----|-----|-----|------|------|
| | 25 and 35 | 69 | 138 | 230 | 287 | 360 | 500 |
| 25 | 0 | 1.5 | 1.5 | 1.5 | 1.5 | | |
| 69 | | 0 | 7.5 | 7.5 | 7.5 | 7.5 | |
| 138 | | | 0 | 12 | 12 | 15 | 18 |
| 230 | | | | 0 | 0 | 13.5 | 16.5 |
| 500 | | | | | | | 0 |

4 Notes:

- 5 1. In absence of information, the sectionalizing substation cost was used.
 6 2. There was no transformation cost assumed since the power line would likely be built at 287, which would be
 7 a similar cost to a 230 kV.

1 **5.4 Comparison to the 2010 ROR**

2 There is no fundamental methodology change in the 2013 ROR Update, but the
3 information obtained in the 2010 ROR was reviewed for material changes to
4 availabilities or costs. BC Hydro resources and those resource options bid into
5 previous acquisitions processes by IPPs have been reviewed and updated.

6 In addition, the UECs and UCCs have been updated for all resource options using
7 BC Hydro's updated Weight Average Cost of Capital to reflect long-term forecasts of
8 project borrowing costs and the lower financing costs available in the markets. In the
9 2013 Update, BC Hydro-owned projects utilized a 5 per cent real cost of capital; third
10 party developed projects utilized a 7 per cent real cost of capital.

2013 Resource Options Report Update

Chapter 6

Unit Energy Cost Adjustment

Table of Contents

| | | |
|-----|---|-----|
| 6.1 | Introduction | 6-1 |
| 6.2 | Adjustments | 6-1 |
| 6.3 | Summary of Adjusted Firm Unit Energy Costs..... | 6-2 |

List of Figures

| | | |
|------------|--|-----|
| Figure 6-1 | Resource Potential Supply Curve Summary – Adjusted Firm UEC Values (\$/MWh)..... | 6-4 |
|------------|--|-----|

List of Tables

| | | |
|-----------|---|-----|
| Table 6-1 | Summary of Supply-Side Energy Resource Options Potential – UEC at POI and Adjusted Firm UEC Values..... | 6-3 |
|-----------|---|-----|

1 **6.1 Introduction**

2 In Chapter 5, the unit energy costs (**UECs**) for each generation resource option at
3 the point of interconnection (**POI**) are shown. These UECs represent the estimated
4 overall cost of both non-firm and firm energy, and are based on the sum of three
5 component-costs: costs within plant gate, road costs, and transmission
6 interconnection costs.

7 In the past (2006 Integrated Electricity Plan and 2008 Long-Term Acquisition Plan),
8 concerns were raised by stakeholders and participants that it is difficult to compare
9 these UECs of resource options with diverse characteristics located in different
10 areas of the province.

11 In order to facilitate a high level comparison of costs across resource types and to
12 reflect the cost of resources delivered to the Lower Mainland (the load centre of the
13 BC Hydro system), a cost adjustment process has been applied. The cost
14 adjustment process assumes that the non-firm energy is valued at the market price
15 from BC Hydro's 2013 market scenario 1 and adjustments are then made to each
16 resource option's firm UEC in order to reflect the cost of delivering firm energy to the
17 Lower Mainland and the value of the resource option in meeting BC Hydro system
18 needs. This process intends to reflect the value and impact the various resource
19 options would have in a supply portfolio, and is similar to the approach taken in bid
20 evaluation during the Clean Power Call processes. In addition, a 5 per cent soft cost
21 adder, which is chosen based on BC Hydro's experience, is applied to reflect the
22 fact that implementing these resource options would entail soft cost expenditures
23 such as environmental assessment, First nation, and stakeholder engagement
24 costs, etc.

25 **6.2 Adjustments**

26 The adjustments applied to each resource option type are summarized as follows:

- 27
- 5 per cent Soft Cost Adder

- 1 • Freshet Firm Energy Adjustment
- 2 • 3 x 12 Time-of-Delivery Price Adjustment
- 3 • Cost of Incremental Firm Transmission
- 4 • Line Losses Adjustment
- 5 • Green House Gases (**GHG**) Offset Costs
- 6 • Capacity Credit
- 7 • Wind Integration Cost

8 A 2 per cent inflation factor was used in instances where it was necessary to inflate
9 dollar values to \$2013.

10 The adjusters are integrated with the base UECs to enable a high level comparison
11 across resource types.

12 It must be noted that these cost adjusters do not reflect the resource option risks and
13 uncertainties (e.g., level of study, resource type uncertainty, earliest in service date,
14 cost uncertainties) or the resource option network upgrade costs (i.e., the cost of
15 interconnecting resource options to the bulk transmission system).

16 **6.3 Summary of Adjusted Firm Unit Energy Costs**

17 [Table 6-1](#) and [Figure 6-1](#) present UECs that have been adjusted to reflect potential
18 costs to BC Hydro customers on an adjusted firm energy price basis using a process
19 similar to the Clean Power Call bid evaluation process.

20 Details of how these adjusters were developed and applied are contained in
21 Appendix 12.

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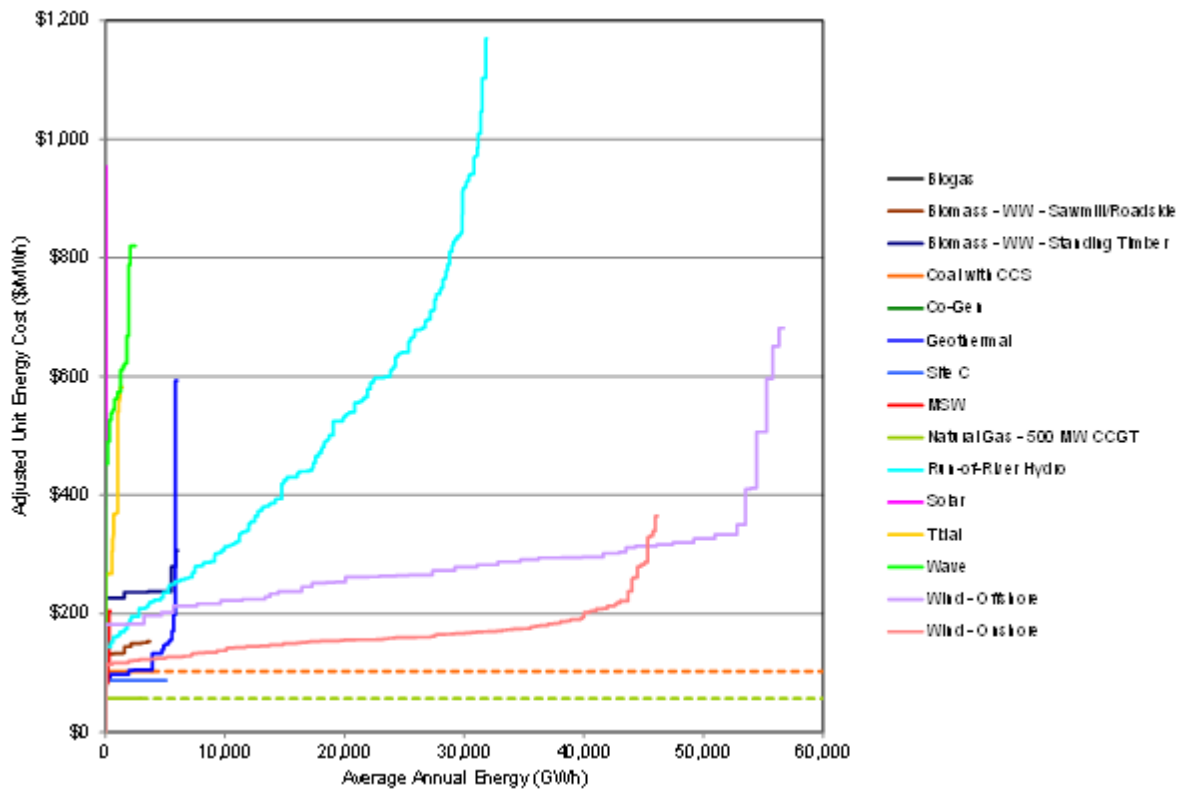
Table 6-1 Summary of Supply-Side Energy Resource Options Potential – UEC at POI and Adjusted Firm UEC Values

| Energy Resource | Total FELCC Energy (GWh/year) | Total DGC or ELCC Capacity (MW) | UEC at POI @ 7% Real (\$2013/MWh) | Adjusted Firm UEC @ 7% Real (\$2013/MWh) |
|--------------------------------|--------------------------------------|--|--|---|
| Biomass – Wood Based | 9,772 | 1,226 | 122 – 276 | 132 – 306 |
| Biomass – Biogas | 134 | 16 | 59 – 154 | 56 – 156 |
| Biomass – MSW | 425 | 50 | 85 – 184 | 83 – 204 |
| Wind – Onshore | 46,165 | 4,271 | 90 – 309 | 115 – 365 |
| Wind – Offshore | 56,700 | 3,819 | 166 – 605 | 182 – 681 |
| Geothermal | 5,992 | 780 | 91 – 573 | 90 – 593 |
| Run-of-river | 24,543 | 1,149 | 97 – 493 | 143 – 1,170 |
| Site C | 4,700 | 1,100 | 83 | 88 |
| CCGT and Cogeneration | 6,103 | 774 | 58 – 92 | 57 – 86 |
| Coal-fired Generation with CCS | 3,896 | 556 | 88 | 103 |
| Wave | 2,506 | 259 | 440 – 772 | 453 – 820 |
| Tidal | 1,426 | 247 | 253 – 556 | 264 – 581 |
| Solar | 57 | 12 | 266 – 746 | 341 – 954 |

4 Note: The Site C values presented in this table are based on information provided in the Site C Environmental
5 Impact Statement (EIS) submission filed in January 2013, and the UEC is calculated assuming 5 per cent real
6 discount rate.

1
2
3

Figure 6-1 Resource Potential Supply Curve Summary – Adjusted Firm UEC Values (\$/MWh)



4 Notes:

- 5 1. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource
- 6 options. Dotted lines indicate additional potential.
- 7 2. The Site C values presented in this figure are based on information provided in the Site C EIS submission
- 8 filed in January 2013.