

Integrated Resource Plan

Chapter 5

Planning Environment

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5.1 Introduction

The IRP compares portfolios using estimated costs and trade revenues of each portfolio over the planning timeframe. These operating costs and revenues are affected by market price assumptions, including the market prices of natural gas, greenhouse gas (GHG) offsets, renewable energy credits (RECs) and electricity.

This chapter contains BC Hydro's assessment of the wholesale electricity market (referred to as the **spot market**), including the major external influences driving spot market prices. External influences are comprised of events and trends affecting the economy and electric power industry market, along with Canadian, B.C. and U.S. GHG and renewable energy policies.

Subsection 6(2) of the B.C. *Clean Energy Act (CEA)* provides that BC Hydro must be self-sufficient by 2016 and each year after that by "holding the rights to an amount of electricity that meets the electricity supply obligations *solely from electricity generating facilities within the Province*" [emphasis added]. Thus BC Hydro cannot plan to rely on external markets to meet its customers' demand for electricity. Nevertheless, external markets are relevant to the IRP analysis and recommended actions for the following reasons:

- BC Hydro plans and operates its electrical system in the context of neighbouring electricity and energy markets. Electricity surpluses or shortfalls are managed through sales in and out of electricity markets. Additional flexibility in BC Hydro's Heritage hydroelectric system is optimized through market transactions. Managing contingency events frequently involves utilities relying upon each other and the market as an ultimate source of back-up power.
- As set out in Chapter 2, BC Hydro forecasts that it has near-term energy and capacity surpluses, and thus external electricity markets set the price for electricity during that time frame and inform BC Hydro's plans to manage the costs of the energy surplus

-
- 1 • Subsection 3(1)(d) of the *CEA* requires BC Hydro to assess the potential for
2 B.C.-based clean or renewable resources to meet any expected export demand
 - 3 • The four market price forecasts described in this chapter (natural gas, GHG,
4 RECs and electricity) are used as an input to the portfolio modelling and risk
5 analysis process. For example, the natural gas and GHG price forecasts inform
6 the cost of natural gas-fired generation in B.C.

7 There are factors with uncertain future costs that are likely to heavily influence the
8 direction of spot market prices. One such factor is the evolution of natural gas prices
9 over the course of the 20-year IRP planning horizon. Given the increased role of
10 natural gas-fired generation in the U.S. portion of the Western Electricity
11 Coordinating Council (**WECC**) region, natural gas prices have become a critical
12 determinant in establishing spot market electricity prices. In addition, regulation of
13 GHG emissions and Renewable Portfolio Standards (**RPS**) result in both costs and
14 benefits for resource options that can influence market prices. To analyze resource
15 options across a range of future electricity prices that are driven by these factors,
16 BC Hydro developed a series of five Market Scenarios. The scenarios are largely
17 focused on possible futures in North American or regional markets; however, where
18 appropriate, international and B.C.- specific considerations are taken into account.

19 The remainder of this chapter is organized as follows:

- 20 • Section [5.2](#) outlines the Market Scenario framework and describes the five
21 Market Scenarios
- 22 • Section [5.3](#) sets out the Natural Gas price forecasts, as well as the trends in
23 these markets. Over the long term, natural gas prices are forecasted to
24 continue to stay low as compared to historical prices due to shale gas reserves.
- 25 • Section [5.4](#) summarizes recent GHG legislative and policy developments.
26 BC Hydro finds that there has been a loss of momentum in U.S. federal and
27 state efforts to develop GHG regulation, e.g., the decision of all U.S. western

1 states, except California, to abandon the Western Climate Initiative (**WCI**).

2 Section [5.4](#) also sets out updated GHG price forecasts.

- 3 • Section [5.5](#) discusses RPS requirements in the U.S. portion of the WECC, and
4 the eligibility of B.C.-based renewables supply under the nine U.S. states in the
5 WECC which have mandatory RPS. A forecast of the incremental value of the
6 RECs associated with renewable electricity generation is provided.
- 7 • Section [5.6](#) provides the resulting spot market electricity price forecasts based
8 on natural gas, GHG and REC price forecasts. BC Hydro's reference spot
9 market forecast at Mid-Columbia (**Mid-C**) ranges from about \$25/MWh to
10 \$40/MWh over the next 20 years.
- 11 • Section [5.7](#) describes the weighting factors assigned to the five Market
12 Scenarios. These weighting factors have been updated to reflect the recent
13 regulatory and market trends highlighted in this chapter.
- 14 • Section [5.8](#) contains BC Hydro's assessment that there are no suitable market
15 opportunities that warrant development of new, additional clean or renewable
16 resources for purposes of exporting electricity for the foreseeable future

17 **5.2 Market Scenario Framework**

18 Any single 'best guess' of where market prices may go in the future is unlikely to be
19 correct. BC Hydro uses Market Scenarios in the IRP to address the uncertainty of
20 market prices and provide a framework to examine a wide range of possible market
21 conditions and resulting different potential price paths that may develop over the
22 planning horizon. Given the exposure of B.C.'s electricity sector through extensive
23 trade with the U.S. market, these market conditions include both domestic and U.S.
24 influences. The main market that BC Hydro transacts in is defined by the WECC
25 region.

26 The development and use of the Market Scenarios is based on a scenario analysis
27 approach in which a scenario is defined as a specified collection of internally

1 consistent¹ variables across a broad range of market situations. In particular, by
2 letting these variables take on specific values (e.g., Scenario X might include GHG
3 prices that are ‘mid’, natural gas prices that are ‘low’ and economic growth as ‘mid’),
4 a scenario will describe a specific way in which markets might unfold.

5 **5.2.1 Market Scenario Development Process**

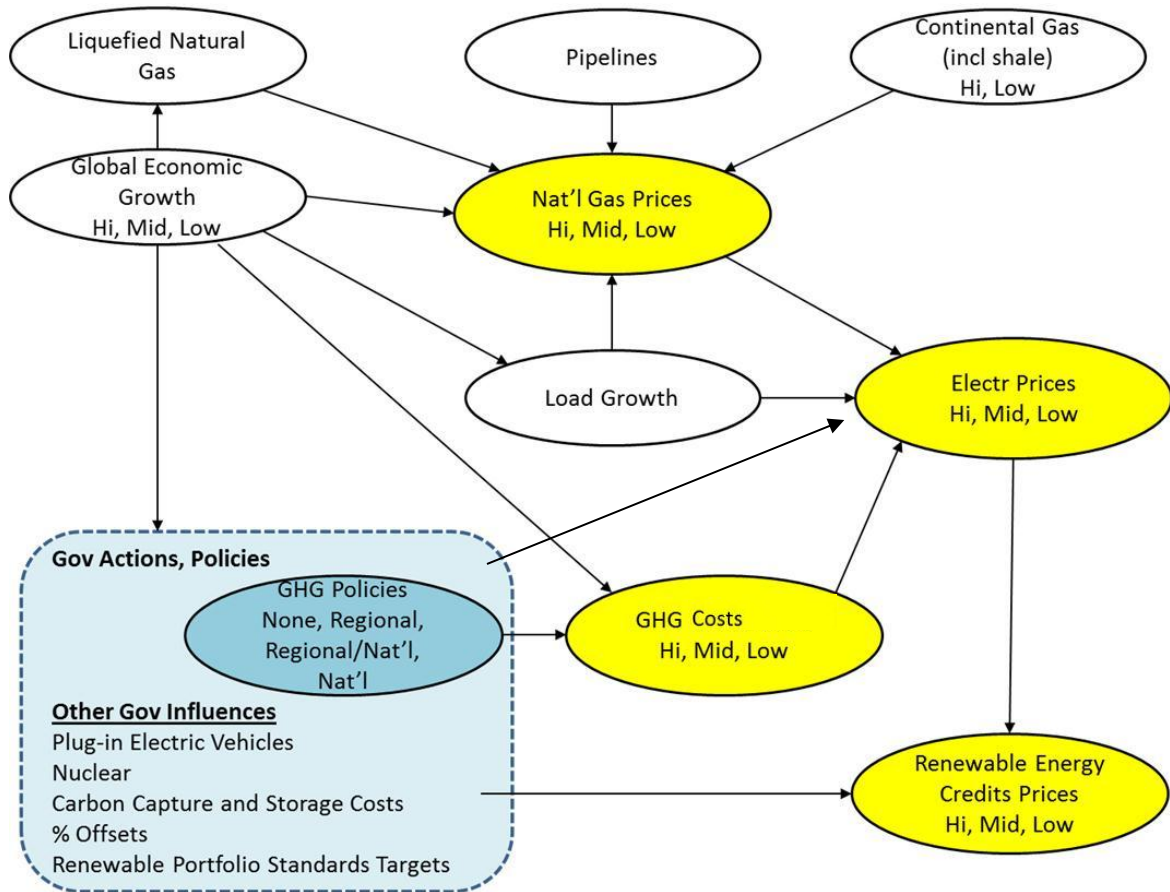
6 The influence diagram depicted in [Figure 5-1](#) shows a view of how a number of
7 market factors interact and highlights the four key price variables of interest (natural
8 gas, GHG, REC and electricity prices).² This diagram portrays the interrelated
9 nature of the variables used in the Market Scenarios. Some of these variables are
10 inputs and some are outputs. The yellow ovals represent the forecast outputs,
11 whereas the other ovals and boxes highlight some of the key input assumptions that
12 help define each Market Scenario.

¹ An internally consistent scenario means all variables are consistent with the overall theme in the scenario.

² BC Hydro retained Black & Veatch (**B&V**) in 2010 to help develop market scenarios and worked with BC Hydro to produce the influence diagram.

1
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Figure 5-1 Simple Influence Diagram for Market Prices



3 Four key market price variables were selected that changed across a wide, but
4 plausible, range of values:

- 5 • Natural gas prices
- 6 • GHG prices
- 7 • REC prices
- 8 • Electricity prices

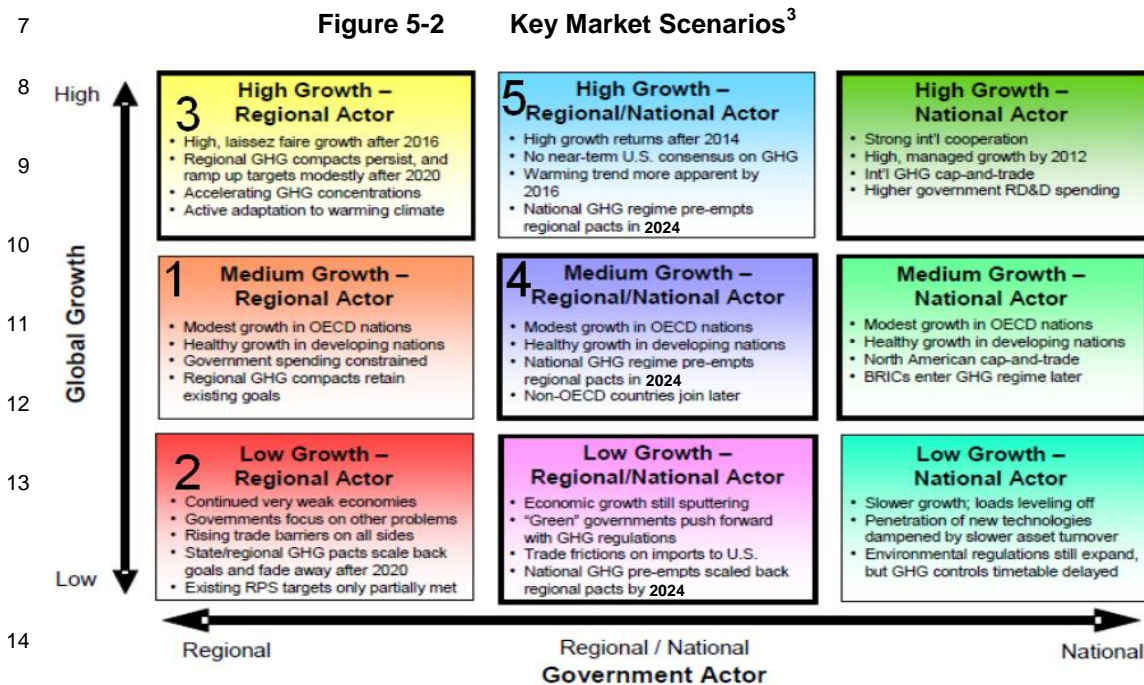
9 In addition, two key drivers from the influence diagram were identified that underpin
10 the four market variables:

-
- 1 • Global economic growth (low, medium, high): Within this driver, a wide range of
2 global economic growth rates are considered, including prolonged periods of
3 global recession. In general, low global economic growth is assumed to stall the
4 development of GHG regulation particularly at the national level and high global
5 economic growth is assumed to lead to faster development of GHG regulation.
 - 6 • Government policy maker (regional, regional/national, national): Within this
7 driver, it is assumed that the level of government that is developing GHG
8 regulation is important to GHG costs. In general, regional GHG markets are
9 assumed to result in higher prices because of the smaller pool of available
10 GHG compliance instruments and lack of competition, whereas the
11 development of national regulation and international protocols results in lower
12 prices.

13 As shown in [Figure 5-2](#), the global economic growth and government policy action
14 drivers are used as the dimensions to create nine possible Market Scenarios.

15 BC Hydro focused on the five scenarios in [Figure 5-2](#), which are labeled Scenarios 1
16 through 5. BC Hydro considers the emergence of a national GHG actor in the U.S. to
17 be unlikely before 2023 particularly in low economic growth scenarios because
18 establishing such a national cap-and-trade regime requires both Presidential and
19 U.S. Congressional legislative action. This does not preclude the emergence of
20 some U.S. federal regulatory initiatives such as U.S. Environmental Protection
21 Agency (**EPA**) targeted sector-by-sector GHG regulation. Given that the overarching
22 principle informing the Canadian Federal Government's GHG policies is to
23 harmonize GHG initiatives with those of the U.S. Federal Government, BC Hydro
24 also considers it unlikely that there will be a Canadian national cap-and-trade or
25 GHG actor; again, this does not preclude targeted sector-by-sector GHG regulation.
26 Therefore BC Hydro eliminated the three scenarios that assume a national GHG
27 cap-and-trade actor beginning in 2013, and the one scenario that assumes a

1 transition to a national GHG cap-and-trade actor in the next 10 years in low
 2 economic growth conditions. Refer to section [5.4.2](#) for the GHG regulatory analysis.
 3 As a result, the five remaining Market Scenarios provide a sufficiently wide range of
 4 possible future outcomes that are adequate to test resources as described in
 5 Chapters 4 and 6. Details on Market Scenario development can be found in
 6 Appendices 5B-1 and 5B-2.



15 Since the release of the draft IRP in May 2012, BC Hydro used Ventyx’s spring 2012
 16 reference and environmental market scenarios⁴ to update the five Market Scenarios.

17 **5.2.2 Description of the Five Market Scenarios**

18 A high level description of the five Market Scenarios is set out in this section.

³ “Regional GHG Actor” means a regional cap-and-trade program that covers Alberta, B.C. and California in the WECC.

“Regional/National GHG Actor” means a linked, national level cap-and-trade program that covers the U.S. and Canada and starts in 2023; “National GHG Actor” means the Canadian or U.S. federal government.

⁴ Ventyx uses its proprietary model called Horizons Interactive that iteratively integrates all the key electricity price market input variables to create an internally consistent market scenario.

1 ***Scenario 1: Mid Electricity Prices, with Regional Mid GHG and Mid Gas Prices***
2 ***– Slow, but steady, global economic growth leads to lack of National GHG***
3 ***regulation in favor of regional regulation***

4 Regional initiatives similar to WCI take the lead in establishing GHG regulatory
5 markets in California, B.C. and Alberta, and national U.S. and Canadian
6 governments do not follow suit in the 25-year forecast period. Medium levels of
7 economic growth reduce federal governments' ability to advance environmental
8 initiatives.

9 ***Scenario 2: Low Electricity Prices, with Regional Low GHG and Low Gas***
10 ***Prices – Low economic growth delays national GHG market development***

11 With slow economic growth and activity, this scenario envisions that GHG emissions
12 start to fall worldwide, impacting the climate change debate and lowering public and
13 government interest in GHG regulation. Lower natural gas prices and flat electricity
14 load growth delay spending on renewable energy development and RPS
15 implementation. Investments in research and development (R&D) and conservation
16 are also down.

17 ***Scenario 3: High Electricity Prices, with Regional Mid GHG and High Gas***
18 ***Prices – High economic growth and lower international cooperation stifles***
19 ***national environmental initiatives, leaving regions to regulate***

20 Although this scenario features high global economic growth, no international
21 agreements on GHG regulation are reached due to low levels of public support for
22 GHG regulation in the U.S. In addition to low GHG support, there is even lower
23 public spending on renewable energy R&D. As with Scenario 1, California, B.C. and
24 Alberta continue to move forward with GHG emission trading.

1 **Scenario 4: Mid Electricity Prices, Regional/National Mid GHG and Mid Gas**
2 **Prices – Mid global economic growth sees regional leaders paving the way for**
3 **national GHG markets by 2024**

4 Mid global growth with regional initiatives similar to WCI take the lead in establishing
5 GHG regional regulatory markets, with national U.S. and Canadian governments
6 following suit by 2024. Although there are delays in national renewable energy
7 standards, development is strong in later years (post-2024), with the electricity
8 prices the same as Scenario 1 for the first 10 years but diverging thereafter.

9 **Scenario 5: High Electricity Prices, Regional/National High GHG and Mid Gas**
10 **Prices – Delayed high economic growth and lower international cooperation**
11 **stifles national environmental initiatives, leaving regions to regulate**

12 Although this scenario sees high global economic growth, a national GHG
13 cap-and-trade program is delayed until at least 2024. International agreements on
14 GHG regulation are not reached for at least 10 years due to low levels of public
15 support for GHG regulation in the U.S., and there is lower public spending on
16 renewable energy R&D. As with Scenario 3, California, B.C. and Alberta continue to
17 move forward with emission trading, albeit under higher cost pressures for market
18 participants, and accordingly electricity prices are the same as Scenario 3 for the
19 first 10 years but diverge after that period.

20 [Table 5-1](#) lists the high level assumptions that informed the five Market Scenarios
21 described above. Populating the four key variables with numerical values is explored
22 in the following sections: Natural gas prices (section [5.3](#)), GHG offset prices
23 (section [5.4](#)), REC prices (section [5.5](#)) and electricity (spot market) prices
24 (section [5.6](#)).

1

Table 5-1 Scenario Assumptions

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
GHG Actor	Regional	Regional	Regional	Regional then National	Regional then National
National Cap-and-Trade Date ⁵	Post-2040	Post-2040	Post-2040	2024	2024
GHG Price Level	Mid (Regional)	Low	High	Mid (Env.)	High
Natural Gas Price Level ⁶	Mid (Regional)	Low	High	Mid (Env.)	High
Global Growth ⁷	Mid	Low	High	Mid	High
Load Growth ⁸	Expected	Flat	High	Expected	High
WECC Resource Build ⁹	Expected Mix	More Gas, Less Coal and Renewable	Less Coal, more Renewable	Less Coal, more Renewable	Less Coal, more Renewable
RPS Targets ¹⁰	Met	Met	Met	Met	Met

2 **5.3 Natural Gas Price Forecast**

3 **5.3.1 Introduction**

4 The most significant development affecting natural gas prices is the emergence of
 5 shale gas. Since 2010, long-term natural gas prices have continued to drop due to
 6 advancements in gas extraction technologies and the increase in shale gas reserves

⁵ 'National Cap-and-Trade Date' is the assumed year for the introduction of a national cap-and-trade system. A three-year period was used to transition from a regional scenario to a national cap-and-trade scenario.

⁶ "Mid (Regional)" is B&V's 2012 spring reference case. "Mid (Env.*)" is B&V's 2012 spring environmental case. "High" and "Low" refers to B&V's spring 2012 high and low natural gas price scenarios, respectively.

⁷ Global Growth "Mid" means 'expected' U.S. and Canada global demand. "High" means almost double the expected year over year compound global growth. "Low" means a flat global growth over the forecast period.

⁸ Load Growth "Mid" means 'expected' U.S. and Canada and regional electric load growth per B&V's spring 2012 reference case. "High" load growth is about two times higher than the expected scenario.

⁹ WECC resource build indicates the type of long-term supply mix changes assumed by B&V in each scenario.

¹⁰ U.S. state RPS targets are met in all scenarios.

1 with U.S. natural gas production increasing to record highs.¹¹ BC Hydro's Natural
2 Gas price forecasts address these shale gas developments and potential Liquefied
3 Natural Gas (LNG) exports, as well as the possibility that environmental concerns
4 may limit shale gas development and cause natural gas prices to rise.

5 The natural gas price forecasts used in the IRP are: (1) an input into the
6 development of the electricity price forecast; and (2) used to define the costs of
7 natural gas-fired generation resource options used in the modelling and risk analysis
8 process.

9 **5.3.2 Forecast Methodology**

10 In developing the IRP, BC Hydro used Ventyx's spring 2012 natural gas price
11 forecast which is consistent with the GHG scenario assumptions listed in [Table 5-1](#).

12 The four natural gas price forecasts are:

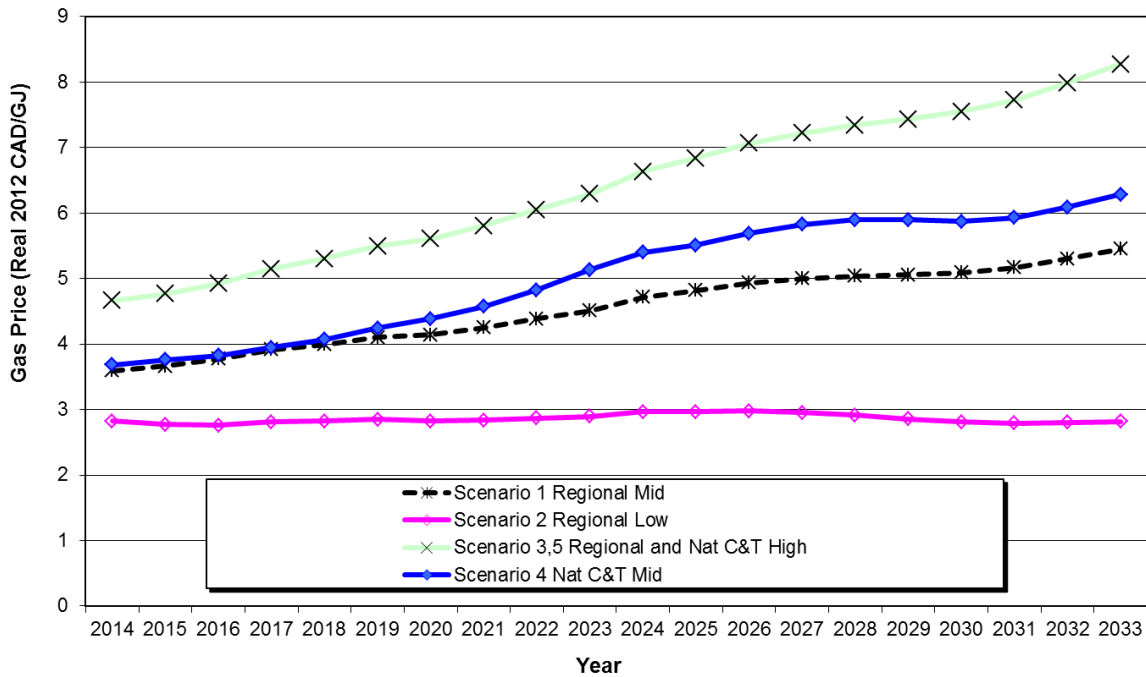
- 13 • **Scenario 1 – Mid Regional Natural Gas Price Forecast:** Ventyx's reference
14 case, which reflects their view of market conditions and includes shale gas
15 supply
- 16 • **Scenario 2 – Low Natural Gas Price Forecast:** Ventyx's low gas price
17 scenario, which assumes flat global demand with limited LNG exports out of
18 North America
- 19 • **Scenario 3 – High Natural Gas Price Forecast:** Ventyx's high gas price
20 scenario, which assumes higher global demand with shale gas environmental
21 issues limiting gas production
- 22 • **Scenario 4 – Mid Environmental Natural Gas Price Forecast:** Ventyx's
23 environmental scenario, which includes an uplift in natural gas demand from the
24 reference case due to additional coal-fired generation retirement

¹¹ Refer, for example, to U.S. EIA figures showing gas production in 2012 reaching 66 billion cubic feet per day.

- 1 • **Scenario 5 – High Natural Gas Price Forecast:** This forecast is the same as
2 the high gas price in Scenario 3.

3 The Ventyx natural gas price forecasts are depicted in [Figure 5-3](#).

4 **Figure 5-3 Ventyx’s Natural Gas Price Forecasts**



5 **5.3.3 Results**

6 [Table 5-2](#) shows the four natural gas price forecasts organized according to how
7 they were used for the five Market Scenarios. The detailed natural gas data tables
8 can be found in Appendix 5A.

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**Table 5-2 Natural Gas Price Forecast Scenarios
(Real 2012 US\$/MMBTU at Sumas)**

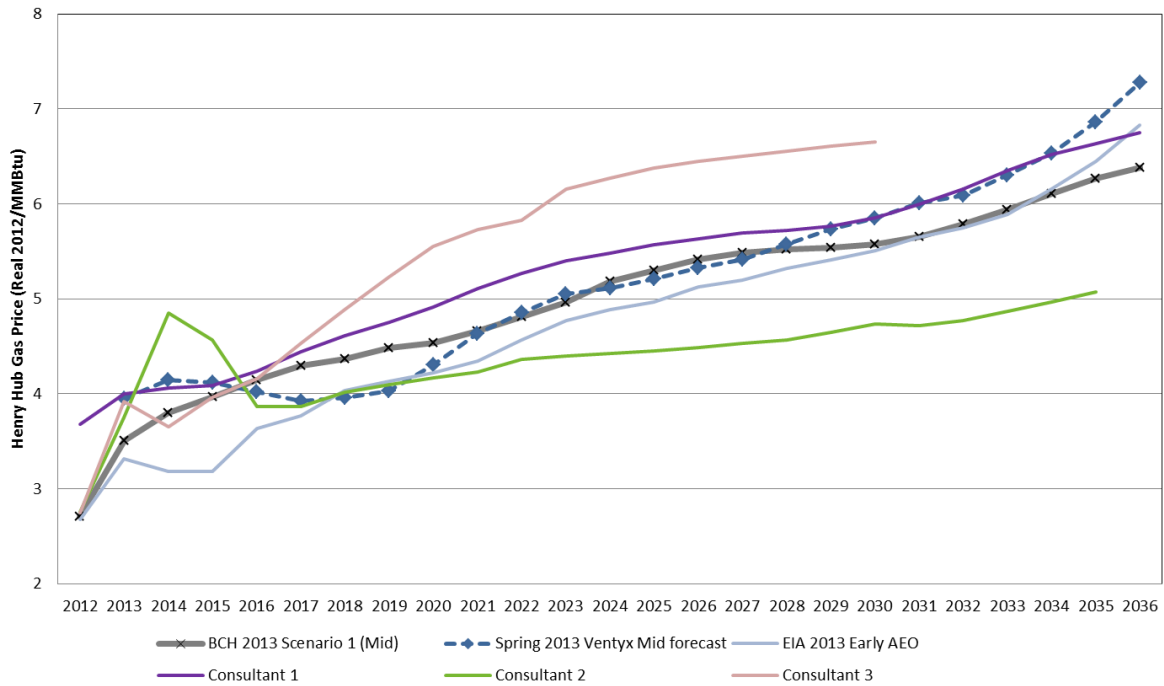
Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
2014	3.7	2.9	4.8	3.8	4.8
2015	3.7	2.8	4.9	3.8	4.9
2016	3.9	2.8	5.0	3.9	5.0
2020	4.2	2.9	5.7	4.5	5.7
2025	4.9	3.0	7.0	5.6	7.0
2030	5.2	2.9	7.7	6.0	7.7

3 BC Hydro tracks and compares its natural gas price forecasts against other external
4 forecasts, such as those produced by the U.S. Energy Information Administration
5 (EIA) and other consultants. A graphical depiction of how BC Hydro’s natural gas
6 price forecasts compare against the U.S. EIA’s 2013 forecast (at Henry Hub¹²), three
7 consultant forecasts and Ventyx’s updated spring 2013 forecast is provided in
8 [Figure 5-4](#). BC Hydro’s Scenario 1 mid forecast is based on Ventyx’s spring 2012
9 forecast. Note that Ventyx’s 2013 forecast is down in the short term but is up in the
10 long term. BC Hydro’s Scenario 1 forecast is slightly higher than U.S. EIA’s 2013
11 forecast for most of the forecast period, but in the middle of the three consultant
12 forecasts.

¹² Henry Hub is a distribution hub in Louisiana on the natural gas pipeline system; it is a pricing point for natural gas future contracts.

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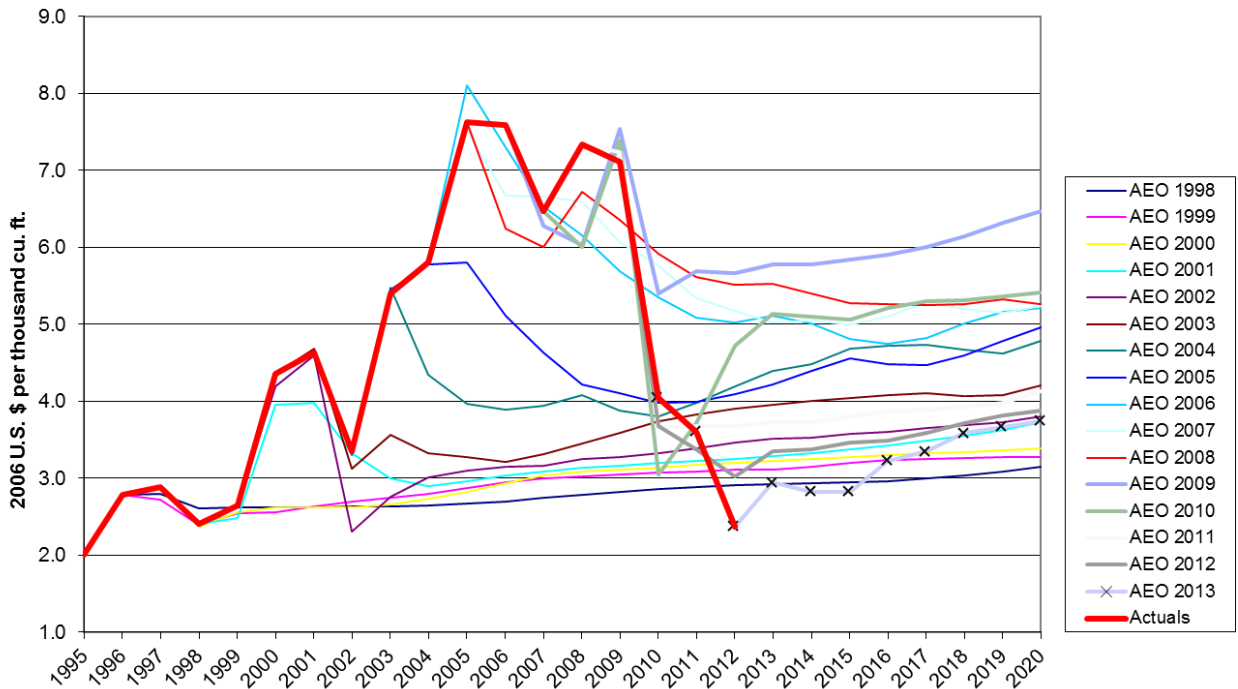
Figure 5-4 Natural Gas Price Forecast Comparison – BC Hydro vs. External Forecasts



3 [Figure 5-5](#), which compares past EIA forecasts to realized spot market prices, is
 4 indicative of the challenges in forecasting long-term energy prices. It is apparent that
 5 the EIA forecasts have been influenced by current conditions, with the result being
 6 that when natural gas spot market prices are low (such as currently), the long-term
 7 price forecast tends to be low and vice versa.

1
2

Figure 5-5 Comparison of EIA Natural Gas Price Forecast U.S. Average Wellhead Price



3 **5.4 GHG Price Forecasts**

4 **5.4.1 Introduction**

5 Since the electricity sector is a significant source of GHG emissions in North
 6 America¹³, a market price on GHG emissions through regulation or otherwise
 7 presents financial risks and opportunities that utilities need to consider in long-term
 8 planning. BC Hydro retained Black & Veatch (**B&V**) in 2011 to: (i) review North
 9 American and international GHG regulation developments; and (ii) develop a GHG
 10 price forecast based on the price of GHG emission allowances, the main market
 11 instrument used under GHG emissions trading (cap-and-trade) systems. BC Hydro
 12 has updated this work as shown in the summaries contained in sections [5.4.2](#) (GHG
 13 regulatory and policy developments) and [5.4.3](#) (GHG offset price forecasts).

¹³ GHG emissions from electricity are primarily from the combustion of coal and natural gas, and vary widely from region to region depending on generation resource mix. The electricity sector emits approximately 42 per cent of GHGs in the U.S., 17 per cent in Canada, and about 2 per cent in B.C.

1 5.4.2 GHG Regulatory and Policy Developments

2 Over the past couple of years GHG policies have been developing slowly. This
3 section covers B.C., Canadian and U.S. federal and WECC state developments.

4 5.4.2.1 Canada – Federal Regulatory Framework

5 The overarching principle informing the Canadian Federal Government's GHG
6 policies is to harmonize GHG initiatives with those at the U.S. federal level. Under
7 the Copenhagen Accord, the Federal Government inscribed a GHG emission
8 reduction target that is aligned with the U.S. federal target, this being 17 per cent
9 below 2005 levels by 2020. The Canadian Federal Government is implementing a
10 sector-by-sector approach to reducing GHG emissions in major emitting sectors as
11 one means of achieving this target.

12 On September 12, 2012, the Canadian Federal Government published the
13 *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity*
14 *Regulations*.¹⁴ These regulations generally take effect on July 1, 2015. Regulated
15 coal-fired generating stations are barred from, on average, producing GHG
16 emissions with an intensity of more than 420 tonnes of carbon dioxide equivalent for
17 each gigawatt hour (**CO₂e/GWh**) of electricity produced during the calendar year.¹⁵
18 The 420 tonnes of CO₂e/GWh performance standard is the GHG emission intensity
19 level of an older vintage Combined Cycle gas Turbine (**CCGT**).

20 BC Hydro understands that Environment Canada is beginning to examine whether
21 and how to regulate GHG emissions from natural gas-fired generators. BC Hydro is
22 engaged through the Canadian Electricity Association.

23 5.4.2.2 Province of B.C.

24 B.C. has a legislated target of reducing GHG emissions to at least 33 per cent below
25 2007 levels by 2020 and at least 80 per cent below 2007 levels by 2050, as set out

¹⁴ SOR/2012-167.

¹⁵ The performance standard in the draft Regulations was 375 CO₂/GWh.

1 in the 2007 *Greenhouse Gas Reduction Targets Act*¹⁶ (**GGRTA**). Two regulations
2 have been enacted under *GGRTA*: (1) the Carbon Neutral Government
3 Regulation¹⁷, which provides in subsection 4(3) that the ‘carbon-neutral public
4 sector’ provisions of *GGRTA* do not apply to BC Hydro’s thermal electricity
5 generating facilities (rather, they apply to BC Hydro corporate functions such as its
6 vehicle fleet); and (2) the Emissions Offset Regulation¹⁸ setting out requirements for
7 GHG reductions and approvals from projects or actions to be recognized as
8 emission offsets for purposes of fulfilling the B.C. Government’s commitment to a
9 carbon-neutral public sector from 2010 onwards. Offsets for carbon-neutral public
10 sector purposes must be sourced in B.C. The Pacific Carbon Trust (**PCT**) is the sole
11 supplier of offsets to the public sector at \$25/tonne for purposes of the carbon
12 neutral commitment, and also provides offsets to the private sector.

13 The B.C. Government passed the *Greenhouse Gas Reduction (Cap and Trade)*
14 *Act*¹⁹ in 2008, which would enable reductions in GHG emissions through a
15 cap-and-trade system and contemplates eventual linkage of a B.C. cap-and-trade
16 system to other systems (refer to section [5.4.2.3](#)). The Reporting Regulation,²⁰ which
17 came into force on January 1, 2010, requires facilities (including electricity
18 generating facilities) emitting 10,000 tonnes or more of GHGs per year to register
19 with the B.C. Ministry of Environment, collect emissions data and report GHG
20 emissions. The development of a B.C. cap-and-trade system would come into force
21 through regulation(s). In 2010 the B.C. Government released consultation papers in
22 respect of two proposed regulations: (1) an Emissions Trading Regulation to
23 establish the rules by which GHG emissions may be traded under a B.C.
24 cap-and-trade system (entails significant oversight of the government distribution of

¹⁶ S.B.C. 2007, c.42. The B.C. Government also established GHG reduction targets of 6 per cent below 2007 levels by 2012 and 18 per cent by 2016 pursuant to Ministerial Order 286 (2008).

¹⁷ B.C. Reg. 392/2008.

¹⁸ B.C. Reg. 393/2008.

¹⁹ S.B.C. 2008, c.32.

²⁰ B.C. Reg. 272/2009.

1 allowances and the spot/cash market for compliance units); and (2) a Cap and Trade
2 Offsets Regulation to set out the requirements applying to project-based GHG
3 emission reductions for them to be recognized as offsets, and eligible for use by
4 regulated emitters to satisfy their compliance obligations in B.C.²¹ To date neither of
5 these two proposed regulations has been brought into force. While B.C. continues to
6 monitor WCI developments, it has not yet made a final decision as to whether to
7 institute a cap-and-trade program.

8 The *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act*²²
9 amends the *Environmental Management Act*²³ to require that new natural gas-fired
10 generation acquire and retire compliance offsets at least equal to the amount of
11 GHG emissions that are created. To date, no regulation has been enacted to bring
12 these provisions into force. However, Policy Action No. 18 of the 2007 BC Energy
13 Plan provides that new natural gas-fired generation is to have net zero GHG
14 emissions, and Policy Action No. 18 would likely be implemented through the
15 *B.C. Environmental Assessment Act (BCEAA)*. New gas-fired electricity generation
16 facilities with a nameplate capacity of equal to or greater than 50 MW trigger *BCEAA*
17 and require an Environmental Assessment Certificate (**EAC**) to proceed. The
18 Environmental Assessment Office (**EAO**) has the power to impose a 100 per cent
19 offset requirement as part of EAC conditions. For example, section 21 of *BCEAA*
20 provides that the EAO executive director may seek policy clarification and direction
21 from the B.C. Ministers of Environment and of Energy and Mines. The policy
22 clarification and direction must be reflected in the environmental assessment
23 conducted by the EAO. Government agencies may also identify relevant policy for
24 the EAO executive director, who then must ensure that the EAO recommendations
25 reflect this policy. For these reasons, a 100 per cent offset requirement is assumed

²¹ <http://www.env.gov.bc.ca/cas/mitigation/ggrcta/emissions-trading-regulation/index.html#intentions>.

²² S.B.C. 2008, c.20.

²³ S.B.C. 2003, c.53. To date one regulation, the Landfill Gas Management Regulation, B.C. Reg. 391/2008, has been enacted; this regulation establishes province-wide criteria for landfill gas capture from municipal solid waste landfills.

1 for new natural gas-fired generation in the Chapter 6 portfolio analysis. Offset costs
2 are discussed in section [5.4.2.3](#).

3 B.C.'s carbon tax²⁴ applies to the purchase or use of natural gas and other fuels
4 within the province. The current tax rate is \$30 per tonne of CO₂e emissions. The
5 Provincial Government committed to freezing the carbon tax at this level for
6 five years as part of the June 26, 2013 Throne Speech.²⁵

7 **5.4.2.3 U.S. – Federal, Regional and State Initiatives**

8 To date, no U.S. federal legislative GHG proposal has successfully been passed by
9 both the House of Representatives and the Senate for consideration by the U.S.
10 President. On February 14, 2013, the *Climate Protection Act of 2013* was introduced
11 into the U.S. Senate which would, among other things, impose a carbon fee of
12 \$20 per ton on coal, oil and natural gas producers beginning in 2014. It is unlikely
13 this bill will become law in the near future given the current realities of the U.S.
14 Congress.

15 The EPA has taken steps to regulate GHG emissions under authority of the U.S.
16 *Clean Air Act*:

- 17 • New Power Plant GHG Performance Standards – On March 27, 2012, the EPA
18 proposed a Carbon Pollution Standard for new power plants that would for the
19 first time set U.S. national limits on the amount of GHGs that power plants can
20 emit. Under the proposal, new fossil fuel-fired electricity generating stations
21 greater than 25 MW must meet an output-based standard of 1,000 pounds of
22 CO₂/MWh (lb CO₂/MWh gross). The EPA selected this threshold based on the
23 performance of widely-used natural gas combined cycle technology. Thus
24 CCGTs could meet this standard, but new coal-fired electricity generators could
25 only meet this standard using CCS. This carbon pollution proposal does not

²⁴ *Carbon Tax Act*, S.B.C. 2008, c.40.

²⁵ *Speech from the Throne*, June 26, 2013, page 4; www.leg.bc.ca/40th1st/Throne_Speech.pdf.

1 apply to Simple Cycle Gas Turbines, existing units or new electricity generating
2 facilities that have permits and start construction within 12 months. While the
3 EPA is proposing a standard of 1,000 lb CO₂/MWh, it is soliciting public
4 comment on a range from 950 lb to 1,100 lb CO₂/MWh (430 to 500 kg/MWh).²⁶

- 5 • Guidance for Best Available Control Technology (**BACT**) – As of July 1, 2011,
6 new facilities that would emit more than 100,000 tons per year of CO₂e must
7 undergo an analysis of emissions-lowering technology before receiving a permit
8 under the U.S. *Clean Air Act*. Proposals must conduct a BACT analysis, which
9 is a five-step process to regulate GHG emissions. The EPA guidance document
10 does not identify what constitutes BACT for specific types of facilities, and does
11 not establish absolute limits on a permitting authority's discretion when issuing
12 BACT determinations for GHGs. State and local authorities review BACT
13 analyses and issue air permits on a case-by-case basis.

14 Legal challenges to various EPA GHG-related regulations have begun.²⁷

15 At the regional and WECC U.S. state level, six states formally withdrew from WCI in
16 November 2011 (New Mexico, Arizona, Washington, Oregon, Montana and Utah),
17 leaving California, British Columbia, Manitoba, Ontario and Quebec as the remaining
18 partners. To date, only California and Quebec have adopted regulations respecting a
19 cap-and-trade system for GHG emissions based on the rules established by the
20 WCI.²⁸ As noted above, B.C. is monitoring developments before deciding whether to
21 enact the regulation on cap-and-trade. On April 19, 2013, the California Air
22 Resources Board (**CARB**, the GHG regulator) approved the linking of California's
23 cap-and-trade program with Quebec's program to start January 1, 2014.

²⁶ PacifiCorp., 2013 IRP, page 34; www.pacificorp.com. In June 2013 the U.S. President requested that the EPA develop regulations for existing fossil-fired electricity generating facilities.

²⁷ Reuters, April 19, 2013. Some of the legal challenges question the authority of the EPA to regulate GHG emissions under the proposals listed above in respect of electricity generating facilities. The U.S. Court of Appeals for the District of Columbia ruled in favour of the EPA in 2012.

²⁸ <http://www.westernclimateinitiative.org/news-and-updates/139-quebec-adopts-cap-and-trade-regulation>.

1 California's cap-and-trade program came into force on January 1, 2013, with
2 enforceable compliance obligations beginning on that date. CARB is to hold auctions
3 of GHG emission permits for the cap-and-trade program. CARB has held three
4 quarterly GHG allowance auctions so far, with GHG price settlements ranging from
5 US\$10.09/tonne to US\$14.00/tonne.²⁹ The prices at which these auctions can settle
6 at are collared by an Auction Reserve Price on the downside (referred to as the
7 **floor price** and currently US\$10.71/tonne) and by an Allowance Price Containment
8 Reserve on the upside (referred to as the **ceiling price** and currently evenly tiered at
9 \$40, \$45 and \$50/tonne).

10 **5.4.3 GHG Price Forecasts**

11 **5.4.3.1 Forecast Methodology**

12 BC Hydro used modelling that was conducted by Ventyx for their spring 2012
13 reference and environmental scenarios to update the five Market Scenarios
14 described in section 5.2. To meet the GHG reduction and avoidance measures,
15 Ventyx's model included:

- 16 • Efficiency improvements
- 17 • Additional renewable capacity
- 18 • Retirement of inefficient coal-fired units
- 19 • Additional natural gas-fired CCGT units in place of new coal-fired units
- 20 • Reduced operation of existing coal-fired units
- 21 • Increased operation of existing gas-fired units
- 22 • Additional nuclear capacity, in regions where this exists or is allowed

²⁹ CARB, "California Air Resources Board Quarterly Auction 3, May 2013: Summary Results Report (June 5, 2013 Update)"; www.arb.ca.gov.

1 As emission caps decrease, GHG prices increase as the supply of emission
 2 allowances decreases over time, which leads to increased use of lower
 3 GHG-emitting electricity generation resources.

4 **5.4.3.2 Results**

5 [Table 5-3](#) summarizes the \$/tonne GHG prices for the five Market Scenarios used in
 6 the IRP. The detailed GHG data tables can be found in Appendix 5A.

7 **Table 5-3 GHG Price Forecast by Market Scenario**
 8 **(Real C\$2012 per Tonne of CO₂e)**

	Scenario 1			Scenario 2			Scenario 3			Scenario 4	Scenario 5
	Mid Electricity Mid GHG (Regional) Mid Gas ³⁰			Low Electricity Low GHG (Regional) Low Gas ³¹			High Electricity High GHG (Regional) High Gas ³²			Mid Electricity Mid GHG (Reg/Nat'l) Mid Gas ³³	High Electricity High GHG (Reg/Nat'l) High Gas ³⁴
	BC	Calif.	WECC Other	BC	Calif.	WECC Other	BC	Calif.	WECC Other	BC, Calif. and WECC Other	BC, Calif. and WECC Other
2014	30	19.5	0.0	30	12.3	0.0	30	67.5	0.0	Same as Scenario 1 to 2023	Same as Scenario 3 to 2023
2015	30	21.9	0.0	30	12.8	0.0	30	70.2	0.0		
2016	30	24.7	0.0	30	13.3	0.0	30	73.0	0.0		
2020	30	39.9	0.0	30	15.5	0.0	30	85.4	0.0		
2025	30	46.7	0.0	30	18.9	0.0	30	103.9	0.0	25.3	103.9
2030	30	51.5	0.0	30	23.0	0.0	30	126.4	0.0	40.4	126.4
2035	30	55.8	0.0	30	26.4	0.0	30	145.1	0.0	54.8	145.1

9 **5.4.3.3 Discussion of Results**

10 The five GHG price forecasts provide a wide range of possible future GHG offset
 11 prices that capture a range of economic and policy scenarios: two high, two mid and

³⁰ Ventyx Spring 2012 Reference Scenario for all GHG forecasts.

³¹ Ventyx Spring 2012 Low Scenario for B.C. and rest of WECC; and CARB floor price for California.

³² Ventyx Spring 2012 High Scenario for B.C. and rest of WECC; and CARB ceiling price for California.

³³ Ventyx Spring 2012 Environmental Scenario for all of WECC after 2023.

³⁴ Ventyx Spring 2012 High Scenario with California ceiling price for all of the WECC after 2023.

1 a low forecast. The GHG price forecasts reflect the increase in uncertainty in
2 implementation of GHG policies, particularly in the short-term at the federal level in
3 the U.S. and Canada.

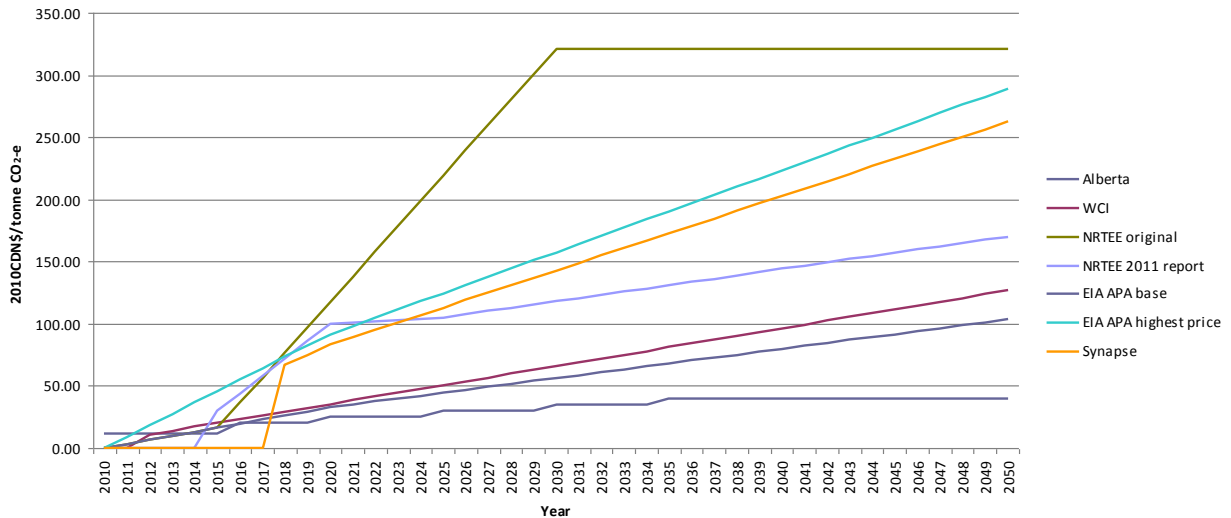
4 BC Hydro benchmarked the GHG prices from the five Market Scenarios against a
5 number of external, publicly available forecasts, which are shown graphically in
6 [Figure 5-6](#).

7 The external GHG price forecasts examined include:

- 8 • WCI Regional Cap-and-Trade Program Economic Analysis Update (July 2010)
- 9 • National Roundtable on the Environment and the Economy (**NRTEE**) “Getting
10 to 2050” (2009) ‘Fast and Deep scenario’ (labeled ‘NRTEE original’ on
11 [Figure 5-6](#)), and NRTEE’s “Climate Prosperity – Parallel Paths: Canada-U.S.
12 Climate Policy Choices” 2011 report ‘Start 2015 scenario’
- 13 • U.S. EIA “Energy Market & Economic Impacts of the *American Power Act of*
14 *2010*”, base case forecast and highest price forecasts
- 15 • Synapse Energy Economics Inc., “2011 Carbon Dioxide Price Forecast”,
16 mid-price forecast
- 17 • Carbon prices in Alberta’s existing regulatory system of GHG emission intensity
18 targets for industrial sectors, which allows compliance flexibility through the use
19 of offsets and investment into a technology fund at a current cost of \$15 for
20 every tonne of GHG emissions above the individual emitter’s limit

21 The forecasts listed above were adjusted to a common unit (2010 C\$/tonne). Where
22 the original reports only included prices for certain years within their respective
23 forecast period, price trajectories to 2050 were determined through straight-line
24 interpolation and extrapolation.

Figure 5-6 Comparison of Publicly Available GHG Price Forecasts



- BC Hydro also examined both the B.C. carbon tax rate of \$30 per tonne of CO₂e emissions and PCT’s \$25/tonne price of offsets offered to the public sector for purposes of the carbon neutral commitment. As described below, BC Hydro utilized the carbon tax as it applies more broadly than PCT pricing.

The GHG price forecasts are used in the IRP analysis in a number of ways:

- As an input to the electricity price forecast, as it is applied to all CO₂-emitting resources in the WECC under a national cap-and-trade scenario and only to Alberta, B.C. and California CO₂-emitting resources in the regional scenarios. This has the effect of uplifting electricity prices.
- As an adder to B.C. CO₂-emitting resources (natural gas-fired generation), as an expected future regulatory cost in the Chapter 6 portfolio analysis. BC Hydro’s analysis assumes that natural gas-fired generation in B.C. would incur the maximum of either the B.C. carbon tax (\$30 per tonne of CO₂e emissions) or the GHG prices shown in [Table 5-3](#).
 - For GHG Scenarios 1, 3 and 5, the B.C. GHG price is greater than the B.C. carbon tax, with this price being driven by U.S. GHG prices.

- 1 ▶ For GHG Scenarios 2 and 4, the B.C. GHG price is lower than the B.C.
2 carbon tax. Therefore the GHG price for B.C.-based natural gas-fired
3 generation is equivalent to the B.C. carbon tax.

4 **5.5 RPS Requirements and REC Price Forecasts**

5 **5.5.1 Introduction**

6 A RPS is a mechanism that places an obligation on electricity suppliers to include a
7 specified percentage of electricity from renewable energy resources such as wind
8 and solar. Currently, 29 U.S. states and the District of Columbia have adopted
9 mandatory RPS requirements, and an additional eight U.S. states have RPS goals.
10 Of the 11 U.S. states that are wholly situated within the WECC region, nine have
11 mandatory RPS requirements and two (Idaho and Wyoming) do not. The RPS
12 requirements vary considerably by state with respect to resource eligibility,
13 allowance for unbundled RECs and enforcement arrangements. The use of
14 unbundled RECs separates the attributes of renewable electricity (e.g., generator
15 emissions) from the electricity itself, creating an entirely separate market for the
16 renewable attribute alone, which is unencumbered by the physical constraints of the
17 transmission grid.

18 REC price forecasts are used to estimate incremental revenue that would result from
19 the sale of the clean or renewable electricity that is surplus to BC Hydro's system
20 need and is RPS-eligible energy. These results inform the export analysis in
21 section [5.8](#) and the portfolio trade-off analysis in Chapter 6.

22 **5.5.2 RPS Summary and Forecast Methodology**

23 **5.5.2.1 WECC U.S. State RPS Summary**

24 In 2011, BC Hydro retained B&V to provide an overview of RPS developments by
25 U.S. state. B&V's findings are documented in the report attached as Appendix 5C.
26 The RPS state requirements in WECC states are summarized in [Table 5-4](#). While

1 there are some ambitious RPS targets in these states, there are restrictions on
 2 hydro resources and delivery requirements.

3 **Table 5-4 RPS Summary for WECC States**

WECC State	Target and Ramp	Hydro Eligibility³⁵	Delivery Requirement	ACP³⁶	Carve-Outs³⁷
Arizona	15 per cent by 2025; 0.5 per cent ramp for 2010-2015, 1 per cent for 2015-2025	<10 MW if run of river or incremental upgrades	Power must be delivered to state since unbundled RECs not allowed	None ³⁸	4.5 per cent DG by 2012
California	33 per cent by 2020; at least 1 per cent ramp annually	Small and conduit <30 MW; must not have “an adverse effect on instream beneficial uses”	Delivery to an in-state hub; tradable RECs allowed up to 25 per cent of RPS requirement, declining to 10 per cent by 2017 ³⁹	None ⁴⁰	None
Colorado	30 per cent by 2020 and each following year (investor owned utilities)	10 MW or less, and hydroelectric resources in existence on January 1, 2005 with a nameplate capacity rating of 30 MW or less	Tradable RECs are permitted	None ⁴¹	None

³⁵ Most states designate solar, wind, geothermal and ocean/tidal to be RPS eligible resources. Other resources like hydro, biomass and waste-to-energy depend on the state and the type of fuel or technology used.

³⁶ The Alternative Compliance Payment (**ACP**) mechanism provides participating entities with an option to obtain the required amount of renewable energy, RECs or make the specified compliance payment. ACPs effectively set a ceiling price.

³⁷ In per cent of total customer sales, not of the RPS requirement, unless otherwise noted.

³⁸ Customer surcharges to comply with the RPS must be approved by the Arizona Corporation Commission; this could create a de facto future limit on price.

³⁹ Rule-making has begun to allow tradable RECs, but is currently in the process of modification before enactment.

⁴⁰ The ACP mechanism in California was deleted under Senate Bill 2 (1X). For the IRP analysis, BC Hydro used the previous ACP price of \$50/MWh.

⁴¹ Colorado State may impose ACP but amounts are not specified.

WECC State	Target and Ramp	Hydro Eligibility³⁵	Delivery Requirement	ACP³⁶	Carve-Outs³⁷
Montana	15 per cent by 2015; 1 per cent ramp for 2010 to 2015	New <10 MW and is not a new water diversion	Must be delivered to Montana; specifies eligibility as Montana or other states	\$10/MWh	75 MW of “community renewable energy projects” ⁴²
Nevada	25 per cent by 2025; 3 per cent ramp every two years	Run of river <30 MW; dams must be existing and used for irrigation only	Power must be delivered into Nevada	None	1.25 per cent solar through 2015; 1.5 per cent thereafter
New Mexico	20 per cent by 2020; 1 per cent ramp per year	All facilities online after July 1, 2007	Power must be delivered to New Mexico; “preference” given to New Mexico facilities	None ⁴³	4 per cent each wind and solar; 0.6 per cent distributed generation by 2020
Oregon	25 per cent by 2025; 1 per cent ramp per year for 2015 to 2025	Efficiency upgrades to existing facilities made after 1994 eligible	Bundled RECs must be located within the U.S.; unbundled anywhere in WECC (limited to 20-50 per cent of compliance)	\$50/MWh ⁴⁴	20 MW small solar by 2020
Utah	20 per cent by 2025; no interim targets	Any size or timing allowed for in-state; out of state limited to upgrades and <50 MW	Delivery to WECC	None	None
Washington	15 per cent by 2020; 6 per cent step changes every five years	Efficiency improvements after March 1999	Must be delivered to WA on a real time basis	\$50/MWh	None

⁴² Projects under 25 MW in size with a controlling interest from local owners.

⁴³ Customer rate increases are limited to 2 per cent per year through 2011, rising by 0.25 per cent per year through 2015.

⁴⁴ Can be adjusted every even-numbered year.

1 BC Hydro also asked B&V to provide a report on renewable market competitiveness
2 in 2011, specifically focusing on Alberta, Washington, Oregon and California. This
3 report is attached as Appendix 5D. The report analyzes the ability of each
4 jurisdiction to meet its RPS or other GHG-reducing requirements with in-state
5 resources. If it seemed likely that there was a gap between the in-state renewable
6 energy resource capacity and the RPS requirements, the competitiveness of B.C.
7 resources was examined. One of the conclusions of the B&V report was that
8 California is the primary potential market for B.C. renewable energy resources.
9 Challenges with accessing the California RPS market are discussed in section [5.5.3](#).

10 **5.5.2.2 Forecast Methodology**

11 BC Hydro retained B&V in 2011 to help develop the REC price forecasts and to
12 provide an objective view as to what the value of RECs would be in the future for
13 each of the five Market Scenarios. B&V concluded that RPS legislation in most
14 WECC states allows a limited amount of out-of-state renewable electricity products.
15 Currently most of the out-of-state RPS-eligible energy space is pre-contracted under
16 long-term contracts, which leaves little room for additional out-of-state RPS energy.
17 Therefore, the 2011 REC price forecast only represents the value of in-state RPS
18 eligible energy and is calculated by the difference between the delivery cost of
19 building new RPS-eligible facilities and the wholesale (spot) electricity market price.

20 B&V's in-state REC price forecasts were not updated because BC Hydro is
21 continuing to use the long-term expected California Senate Bill 2 First Extraordinary
22 (**SB 2-1X**) Product Content Category 3 out-of-state REC price of up to \$4/MWh as
23 described in section [5.5.3](#). Currently these Category 3 out-of-state REC prices are
24 around \$1.25/MWh. The 2011 unbundled REC price forecast can be found in
25 Appendix 5C.

26 **5.5.3 Discussion of Results**

27 B.C. resources currently have challenges accessing RPS markets in the U.S.
28 because of delivery and resource eligibility requirements. This is particularly the

1 case for the California where SB 2-1X (signed in April 2011) contains California's
2 RPS resource eligibility and delivery requirements.

3 With respect to resource eligibility, the California Energy Commission (**CEC**) is
4 required to evaluate the "eligibility" of B.C.-based low-impact hydroelectric
5 generation and to report to the California legislature as part of implementing
6 SB 2-1X. In March 2013, a CEC-retained consultant released a report⁴⁵ analyzing
7 the regulatory requirements for inclusion of B.C. run-of-river facilities in California's
8 RPS. To be considered eligible for California's RPS, projects located outside the
9 U.S. must be developed and operated in a manner that is as protective of the
10 environment as a similar facility located in California. The CEC consultant concluded
11 that while B.C. run-of-river facilities "going through a full environmental assessment
12 in British Columbia must adhere to similar regulatory requirements as those in
13 California ... a [B.C.] run-of-river hydroelectric project would have to meet additional
14 requirements to be considered eligible for California's [RPS]". The CEC consultant
15 also concluded that "benefits [of B.C. run-of-river] do not warrant changing existing
16 statutory requirements to categorically allow all run-of-river hydroelectric projects in
17 British Columbia to become eligible for California's [RPS]".

18 The consultant notes that the CEC is considering the following requirements for
19 B.C.-based run-of-river projects requesting eligibility:

- 20 • The project must be less than 30 MW
- 21 • The project must complete an environmental assessment or development plan
22 with a cumulative impact assessment based on the Agency's "Cumulative
23 Effects Assessment Practitioners Guide"⁴⁶

⁴⁵ "Analysis of Regulatory Requirements for Including British Columbia Run-of-River Facilities in the California Renewables Portfolio Standard" by Suzanne Phinney and Emily Capello (Aspen Environmental Group), March 2013 (CEC -300-2013-006).

⁴⁶ Published by the Canadian Environmental Assessment Agency.

-
- 1 • Instream flow requirements must be sufficient to not compromise the river
2 ecosystem based on volume or timing of streamflow
 - 3 • The project should obtain EcoLogo certification⁴⁷
 - 4 • Documentation (which may or may not be EcoLogo) must be provided to show
5 the project was analyzed, constructed and operated to protect the environment
6 in a similar manner as would be required of a California project
 - 7 • Transparency during the environmental review and monitoring process should
8 be comparable with Federal Energy Regulatory Commission standards⁴⁸

9 With respect to delivery requirements, SB 2-1X allows for RPS requirements to be
10 met from three Product Content Categories or 'buckets'. The price ranges set out for
11 each of the three buckets have been obtained from discussions with Powerex and
12 other sources:

- 13 • Category 1: This is a bundled REC product, meaning the associated renewable
14 energy from facilities interconnected to a California balancing authority or
15 otherwise meeting certain deliverability requirements. If a California retail seller
16 is purchasing a Category 1 product from outside of California, they must be
17 able to prove they have scheduled the electricity into a California balancing
18 authority without substituting electricity from another source. This criterion
19 requires the retail seller to purchase energy and the associated RECs from a
20 renewable facility and, for out-of-state facilities, demonstrate the energy has
21 been transmitted via dynamic scheduling or a continuous transmission
22 schedule from the facility into a California balancing authority. This marks a
23 reduction in flexibility from the previous rules which allowed the separate
24 purchase of energy and RECs, which then could be bundled together in a

⁴⁷ EcoLogo is an environmental standard and certification mark founded in 1988 by the Government of Canada.

⁴⁸ Aspen Environmental Group report, pages 1-3 and 66.

1 contract to satisfy the RPS compliance mandates of retail sellers.⁴⁹ This
2 category represents the largest market for California RPS products, as SB 2-1X
3 significantly restricts the eligibility of the other two categories. Category 1
4 currently attracts the highest prices of up to \$20/MWh to \$30/MWh; however,
5 the enhanced delivery requirements incur expensive transmission costs.

- 6 • Category 2: This is also a bundled REC product and refers to the product
7 coming from renewable facilities not directly connected to a California balancing
8 authority and delivering power using firming and shaping. Out-of-state
9 generators represent the biggest suppliers of the Category 2 product.
10 Load-serving entities can use Category 2 RECs to satisfy up to one-half of
11 current RPS obligations and reduced to 25 per cent by 2017. The oversupply of
12 renewable energy already constructed in the WECC region results in sufficient
13 resources to meet the majority of this need. Recent market prices for this
14 product have been around \$4/MWh.
- 15 • Category 3: This is an unbundled product (or tradable REC) meaning that the
16 REC is separated from the energy to meet RPS requirements. According to SB
17 2-1X, the use of tradable REC transactions signed after June 10, 2010, will be
18 capped at 25 per cent for the compliance period ending December 31, 2013,
19 and will shrink to 10 per cent of the requirement by 2017. Tradable RECs are
20 the least expensive REC product on the market, as existing supply keeps
21 recent prices relatively low at about \$1.25/MWh.

22 Because of the high delivery costs and transmission requirements associated with
23 Category 1, it will be challenging for B.C. resources to deliver this product. As the
24 size of the 'out-of-state' market associated with Categories 2 and 3 will shrink over
25 the next few years, it is expected that REC prices will remain low due to excess
26 supply.

⁴⁹ Under previous rules, firming and shaped energy was categorized as the same as renewable energy from an in state generator.

1 For the IRP portfolio analysis, BC Hydro applied the following assumptions:

- 2 • Eligibility – The resource options analysis in Chapter 3 demonstrates that the
3 technically or economically feasible B.C.-based clean or renewable resources
4 are Site C, Resource Smart upgrades to existing BC Hydro hydroelectric
5 facilities, pumped storage, run-of-river, biomass and wind. Of these resources,
6 only wind and biomass are assumed to be eligible for REC sales. BC Hydro will
7 monitor developments in CEC’s assessment of the eligibility of low impact
8 hydroelectric generation but it is currently considered to be ineligible.
- 9 • Prices – REC prices are capped at \$4/MWh, based on the range of recent
10 out-of-state REC prices and the expectation that excess supply will constrain
11 prices over the next few years. The WECC power supply situation is discussed
12 in section [5.8](#).
- 13 • REC Sales – BC Hydro will only sell RECs to the extent that the underlying
14 energy is surplus to customer needs.

15 **5.6 Electricity Price Forecast**

16 **5.6.1 Introduction**

17 WECC’s electricity and natural gas markets are closely linked since natural gas has
18 become the predominant fuel for new electricity generation. This is due to natural
19 gas-fired generation’s operational flexibility and relatively high variable operating
20 costs, which typically place it last in the order of generation resources to be
21 dispatched. As such, natural gas-fired generation is the marginal market resource
22 and low gas prices are likely to drive low electricity market prices through most
23 periods in a year.

24 Five electricity price forecasts were developed for the IRP based on the Ventyx
25 Market Scenarios. The sales and purchases assumed to be made in the analysis are
26 based on pricing at two external trading hubs – the Mid-C and the Alberta Energy

1 System Operator hubs. In each case, wheeling and losses are captured from the
2 B.C. delivery point to the respective hub.

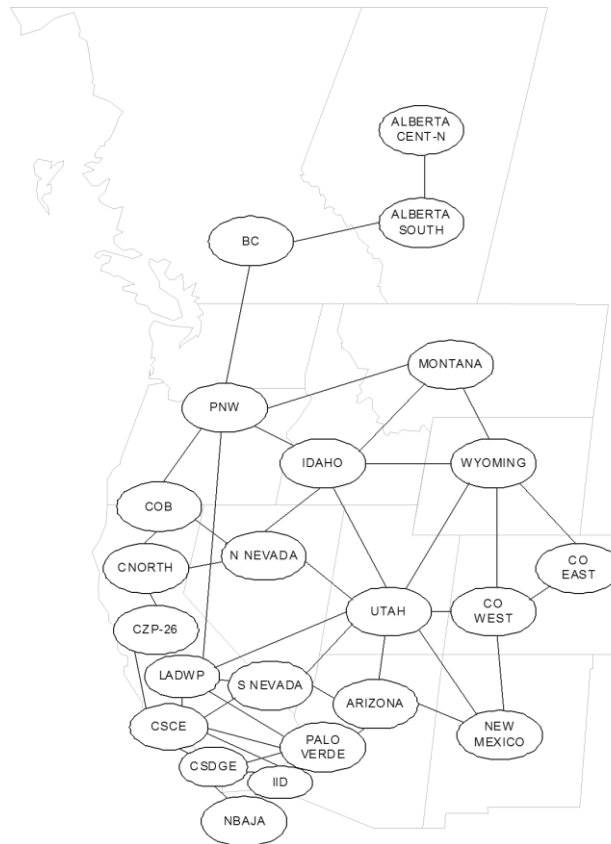
3 **5.6.2 Forecast Methodology**

4 Electricity prices are modelled under a computer simulation of the hourly
5 supply-demand balance for the WECC regional market. The dispatch cost of the
6 marginal resource at the point where supply and demand are in equilibrium
7 determines the market price for that hour. Monthly and yearly average prices are
8 obtained by aggregating the computed hourly prices. The electricity and natural gas
9 prices are calculated for the next 25 years.

10 The electricity price forecasts were developed using a two-stage process. In the first
11 stage, Ventyx compiled a database of scenarios of loads and resources in the
12 WECC region. These scenarios include underlying assumptions for demand-side
13 management (**DSM**), clean or renewable resources and conventional resources in
14 each region (refer to [Figure 5-7](#)) and correspond to the Market Scenarios.

1

Figure 5-7 WECC Transmission Area Configuration



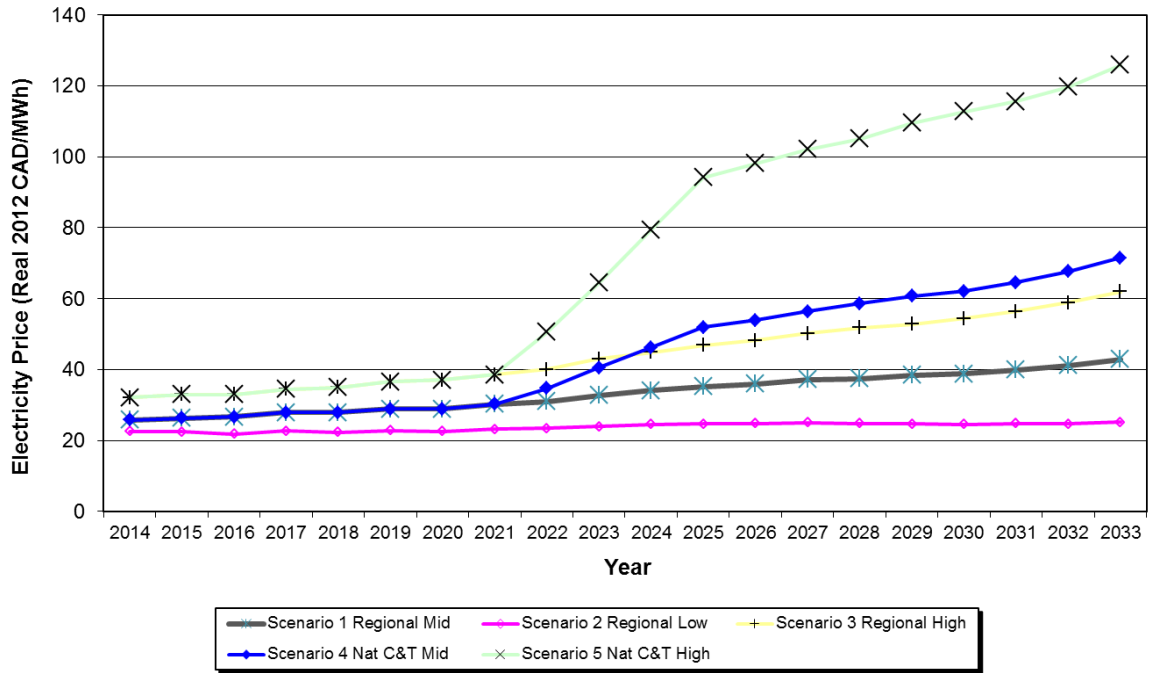
2 In the second stage, BC Hydro made certain modifications to the Ventyx database
 3 with respect to the B.C. area, including additional precision with respect to BC Hydro
 4 resources. BC Hydro then simulated the impact of the natural gas and GHG price
 5 forecasts described in sections [5.3](#) and [5.4](#), respectively, on the WECC region. For
 6 the two national cap-and-trade scenarios BC Hydro assumed that a U.S. national
 7 cap-and-trade program will not be implemented any earlier than 2023, and therefore
 8 Scenarios 4 and 5 are the same as Scenarios 1 and 3 respectively, up until 2023.

9 **5.6.3 Results**

10 The electricity price forecasts for Mid-C in U.S. dollars are provided in [Figure 5-8](#)
 11 and [Table 5-5](#). The detailed electricity price forecast data tables can be found in
 12 Appendix 5A.

1

Figure 5-8 Electricity Price Scenarios at Mid-C



1
2

Table 5-5 Electricity Price Forecasts by Market Scenario (Real 2012 US\$/MWh at Mid-C)

Market Scenario	1	2	3	4	5	
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Region/Nat'l) Mid Gas	High Electricity High GHG (Region/Nat'l) High Gas	
2007	55.7	55.7	55.7	55.7	55.7	Historical
2008	62.9	62.9	62.9	62.9	62.9	
2009	33.9	33.9	33.9	33.9	33.9	
2010	33.5	33.5	33.5	33.5	33.5	
2011	23.2	23.2	23.2	23.2	23.2	
2012	18.6	18.6	18.6	18.6	18.6	
2013	21.8	21.8	21.8	21.8	21.8	
2014	25.0	21.9	31.1	25.0	31.1	Forecast
2015	25.5	21.7	31.9	25.5	31.9	
2016	25.8	21.2	32.0	25.8	32.0	
2020	28.0	21.9	36.0	28.0	36.0	
2025	34.2	24.0	45.4	50.3	91.2	
2030	37.6	23.8	52.7	60.1	109.3	

3 **5.6.4 Discussion of Results**

4 As [Table 5-5](#) shows, there is a wide range of possible future electricity market
5 prices, which is viewed as being appropriate for use in long-term electricity planning
6 as there can be significant variability and volatility with electricity prices.

7 Scenario 1 is BC Hydro’s reference scenario and reflects current market conditions
8 being prolonged over the long term. Currently there is an energy oversupply in the
9 WECC due to:

- 10 • Slower electricity demand growth since the 2008 recession
- 11 • Increases in clean or renewable electricity generation driven by U.S. federal and
12 state policies such as RPS and the U.S. tax incentives in section [5.8.2](#)

1 Scenario 1 aligns with the Northwest Power and Conservation Council's Mid-C
2 electricity price forecast 'No Federal CO₂ Policy' scenario.⁵⁰ In interpreting these
3 results, it is important to note that BC Hydro's Electricity price forecasts are based
4 on spot market price forecasts, and do not necessarily reflect the cost of building
5 new supply. In addition, they indicate yearly averages and do not show seasonal
6 variability that is embedded in the forecast details.

7 **5.7 Market Scenario Weightings**

8 **5.7.1 Introduction**

9 Weighting factors are used in the IRP to assign a relative probability to each
10 scenario and are part of the overall modelling and risk analysis process described
11 further in Chapter 4. There have been some significant and important developments
12 to the policy and market context over the last year:

- 13 • Long-term natural gas prices continue to be low due to shale gas reserves and
14 advancements in gas extraction technology (section [5.3](#))
- 15 • Slower implementation of U.S. national and regional GHG policies and
16 regulations (section [5.4](#))
- 17 • Changes to California's RPS requirements (section [5.5](#))
- 18 • Lower electricity demand growth since the 2008 recession (section [5.6](#))
- 19 • Oversupply of renewables in WECC due to U.S. tax incentives (section [5.8](#))

20 The process of developing the weighting factors, the results and the process used to
21 update the weighting factors are described in the following section.

⁵⁰ Northwest Power and Conservation Council's (NPCC), Draft Sixth Power Plan Mid-Term Assessment Report; <http://www.nwcouncil.org/library/2012/2012-13.pdf>. NPCC is a regional organization (Idaho, Montana, Oregon and Washington) that develops a 20-year regional power plan to balance energy and environmental needs. Mid-C electricity prices under the NPCC's 'Delayed Federal CO₂ Policy' scenario return to a \$50/MWh to \$60/MWh level from 2020 onward.

5.7.2 Market Scenario Weighting Factors

In 2011, BC Hydro worked with B&V to assign relative likelihoods to each of the five Market Scenarios.⁵¹ This exercise considered the relative likelihood of the whole scenario and not the underlying variables or drivers. These estimates were developed using a Modified Delphi method, which systematically assists experts to reach a consensus on the relative probabilities.

In developing the 2013 Market Scenarios, BC Hydro assigned weighting factors to the Scenarios. BC Hydro reviewed the four variables associated with the five Market Scenarios and ranked the scenarios from most likely to least likely, as follows:

- Scenario 1, which is based on Ventyx's spring 2012 reference forecast, is the most likely scenario
- Scenario 5 (high electricity price, high GHG price due to national government GHG regulation and high natural gas price) is the least likely based on shale gas development and the stalled development of GHG regulation at the U.S. federal level (with the resulting slower development of Canadian federal GHG regulation given that the Government of Canada's position that it will harmonize GHG regulation with U.S. federal government actions)
- Scenario 4 is not likely as it assumes a national GHG cap-and-trade program
- Scenarios 2 and 3 assume regional as opposed to national GHG cap-and-trade regulation. BC Hydro determined that Market Scenario 2 was more likely than Market Scenario 3 as lower natural gas prices would be expected to prevail over the IRP planning horizon.

The results are shown in [Table 5-6](#).

⁵¹ Likelihoods are not to be taken as the probability that one scenario will occur. Given the infinite ways market prices can unfold, the chance that any one of these scenarios will exactly occur is essentially zero. The use of the term 'relative likelihood' emphasizes that these judgments are made in relation to the other scenarios.

1 **Table 5-6 Final 2012 Updated Relative Likelihoods**

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Region/Nat'l) Mid Gas	High Electricity High GHG (Region/Nat'l) High Gas
Relative Likelihood	60%	20%	15%	4%	1%

2 **5.8 Electricity Export**

3 **5.8.1 Introduction and Definition of ‘Export’**

4 The *CEA* in subsection 2(n) sets an objective for the province to “be a net exporter
5 of electricity from clean or renewable resources with the intention of benefiting all
6 British Columbians and reducing greenhouse gas emissions in regions in which
7 British Columbia trades electricity while protecting the interests of persons who
8 receive or may receive service in British Columbia”. Section 3(1)(d) of the *CEA* sets
9 out the following requirement for what the IRP must include with respect to meeting
10 this objective:

- 11 (d) a description of:
 - 12 (i) The expected export demand during a defined period
 - 13 (ii) The potential for British Columbia to meet that demand
 - 14 (iii) The actions the authority has taken to seek suitable
15 opportunities for export of electricity from clean or renewable
16 resources
 - 17 (iv) The extent to which the authority has arranged for contracts for
18 the export of electricity and the transmission or other services
19 necessary to facilitate those exports
- 20 (e) if the authority plans to make an expenditure for export, a
21 specification of the amount of the expenditure and a rationale for
22 making it.

23 These requirements are addressed in this chapter.

1 Traditionally, BC Hydro built its system to meet domestic electricity demand, while
2 Powerex conducted trade using surplus capability in the BC Hydro system, as it
3 existed from time to time, which provided benefits such as lower electricity rates and
4 hundreds of millions of dollars of Provincial revenue. This trade activity has, and
5 continues to result in, both imports and exports of electricity. These trade-related
6 exports are not the focus of the CEA's objective to be a net exporter of electricity,
7 and BC Hydro and Powerex will continue this trade activity to the benefit of
8 BC Hydro's ratepayers and the Province.

9 The CEA's reference to exports is in the context of developing new clean or
10 renewable generation resources in B.C. beyond domestic need for the express
11 purpose of exporting the electricity from those resources to electricity markets
12 outside of B.C. Therefore, it is necessary to distinguish between:

- 13 (a) Exports that arise through the sale of surplus capability and the firm and
14 non-firm energy associated with acquiring resources to meet domestic load
15 self-sufficiency requirements; versus
- 16 (b) Exports that come from the acquisition of additional generation resources and
17 investment in transmission for the purpose of selling electricity in the U.S. over
18 and above the self-sufficiency requirements. The use of the term 'export' in the
19 balance of this section refers to this type of export.

20 **5.8.2 Market Opportunities**

21 There are two types of potential export market opportunities: the spot electricity
22 market and the RPS market. The following sections describe these market
23 opportunities which are defined as:

- 24 • **Electricity (Spot) Market** – refers to the generation and usage of all electricity
25 that does not have to meet a RPS. It is and will continue to be the largest
26 market for electricity. There are currently no restrictions on the type of

1 generation that can be used to meet demand in this market. It is served by
2 utilities' self-generation, long-term contracts and spot market transactions.

- 3 • **RPS Market** – Section [5.5](#) describes the RPS markets in the WECC U.S.
4 states.

5 **5.8.2.1 Electricity Market**

6 Opportunities in this market are governed by the overall supply/demand balance and
7 the price of natural gas. Because of North American shale gas developments,
8 natural gas prices have come down in recent years, and as per BC Hydro's
9 Scenario 1 mid natural gas price forecast will be about \$4/mmbtu over the next
10 decade, which equates to about \$30/MWh power prices as described in section [5.6](#).
11 With the exception of Alberta, the combination of the economic recession and the
12 addition of electrical generation for RPS/renewable compliance purposes in
13 neighbouring jurisdictions have resulted in an excess supply of generation with
14 reserve margins at relatively high levels when compared to the past decade. This
15 keeps prices relatively low due to capacity shortfalls. Lower prices generally imply
16 lower spreads between market regions than has been experienced over the past
17 decade.

18 There are two areas where market opportunities may arise. First, the increase in
19 non-dispatchable power generation (i.e., wind) to the grid has the potential to
20 increase price volatility. Recent experience has shown that prices can be driven to
21 low levels (even into negative market prices). This can create a daily spread (i.e.,
22 buying power during an hour when prices are lower and selling it back when prices
23 are higher) and regional spread (i.e., buying in a lower-priced region and selling to a
24 higher-priced region). However, these market opportunities now typically are of
25 shorter duration and are much less predictable than in the past due to lower natural
26 gas prices and other market conditions. Real-time market intelligence systems and
27 the ability to transact quickly are key to capturing opportunities in this area. These
28 opportunities relate more to system capacity and flexibility as opposed to outright

1 energy sales. In a depressed market price environment, having a surplus energy
2 position will reduce system flexibility and make it difficult to avoid selling into
3 low-priced periods.

4 The second opportunity is associated with the potential passage of any U.S. federal
5 or WCI climate change legislation which aims to reduce GHG emissions and/or
6 establish a price on CO₂. The value of these opportunities will be affected by the
7 specifics of the rules, but generally would involve market sales of clean or renewable
8 energy to parties using GHG intensive energy (e.g., coal) to displace such non-clean
9 resources. While this carbon market opportunity is more aligned with a surplus
10 energy position, there remains a large policy uncertainty. As discussed in
11 section 5.4, U.S. federal GHG legislation appears to be stalled; there remains
12 uncertainty regarding EPA proposals to regulate GHG emissions of new power
13 plants; and the regional WCI is not proceeding as originally envisioned. That said, as
14 discussed earlier, California has implemented cap-and-trade in the electricity sector
15 with electricity prices rising by about \$6/MWh to \$7/MWh since implementation,
16 taking into consideration the value of the carbon market in California.

17 In addition, any market opening for sales of clean or renewable capacity-backed
18 resources is expected to be quite limited given price competition from CCGTs which
19 are lower priced than B.C.'s clean or renewable resources. Finally, the types of
20 clean or renewable resources that B.C. is best suited to provide to this market (e.g.,
21 large and small hydro) are not the types of resources that are currently acceptable in
22 the RPS market as described in section [5.5.2](#).

23 **5.8.2.2 RPS/Renewable Compliance Market**

24 Given the current market conditions for electricity and the cost of B.C.'s clean or
25 renewable resources set out in Chapter 3, the expectation is that exports beyond
26 B.C.'s self-sufficiency energy would be sold into the RPS compliance market. In
27 general, this market is driven by compliance concerns rather than broad economic
28 competition and as a result prices tend to be higher as they reflect the full cycle

1 costs of new construction. There is also more room for deal customization in the
2 RPS/compliance market than the regular electricity market.

3 However, there are a number of hurdles. First, as described in sections [5.5.1](#) and
4 [5.5.2](#), hydroelectric resources are generally not eligible for RPS purposes. As
5 discussed in section [5.5.3](#), California remains by far the largest market for renewable
6 compliance resources due to its sheer size and the aggressiveness of its RPS
7 targets. However, California utilities are constrained in procuring certain B.C.-based
8 resources such as run-of-river hydro which are not recognized as “renewable”. Much
9 of the electricity generated in B.C. is not eligible to be sold into this market.

10 Approximately 50 per cent of the contracted energy volumes for EPAs awarded in
11 BC Hydro’s Clean Power Call were for run-of-river projects. Much of the surplus
12 energy arising from B.C. self-sufficiency is not eligible to be sold into this market
13 segment.

14 A second key issue is U.S. government tax incentives. Canadian resources are at a
15 significant cost disadvantage of at least 25 per cent due to various U.S. tax credit
16 and accelerated depreciation programs. The U.S. federal government offers:

- 17 • Investment Tax Credit of 30 per cent of the initial investment to solar
18 developers
- 19 • Production Tax Credit of 2.1 cents per kWh to wind and geothermal developers
- 20 • Accelerated depreciation under a five-year ‘Modified Accelerated Cost
21 Recovery System’

22 Canada offers accelerated depreciation on a less aggressive basis, and does not
23 have a comparable tax credits. While the U.S. tax incentives are set to expire over
24 the next few years, the U.S. Congress has acted several times in recent years to
25 retain them. Reduction of these incentives would improve the competitiveness of
26 B.C. clean or renewable energy in U.S. markets.

1 A third key issue is competition from other renewable resource producers within the
2 WECC region. Certain states such as Wyoming and Montana have good wind
3 regimes that coupled with the tax credits and a small local demand create a very
4 price competitive pool of resources located relatively close to the main RPS market
5 in California. However, these states lack integration capability and appropriate
6 transmission infrastructure. Furthermore, there has been an oversupply of wind
7 energy in the Pacific Northwest in recent years due to federal U.S. tax incentives.
8 Within California, significant efforts have been made by state agencies to streamline
9 siting and permitting of solar facilities to take advantage of U.S. federal stimulus
10 funding. Compliance filings by the major California utilities show a significant portion
11 of future RPS demand will be met by in-state solar developments. Given the relative
12 immaturity of this market segment, there is still a relatively higher attrition and/or cost
13 risk associated with these solar projects.

14 **5.8.3 Demand for Clean or Renewable B.C. Resources**

15 BC Hydro retained B&V to examine the market competitiveness and acceptance of
16 B.C. clean or renewable energy products in the markets of California, Washington,
17 Oregon and Alberta. B&V's report is attached as Appendix 5D. B&V assessed the
18 potential demand for renewable energy to meet both RPS requirements, as well as
19 carbon markets in Alberta and the U.S. The competitiveness of B.C. clean or
20 renewable energy products was also tested against several market and product
21 sensitivities using B&V's Renewable Energy Market model.

22 **5.8.3.1 Demand in Export Markets**

23 The B&V study assessed the potential demand for renewable energy in three key
24 U.S. states with RPS requirements, as summarized in [Table 5-7](#).

1

Table 5-7 RPS Market Potential

	RPS Target	Flat Growth (GWh)	High Growth (GWh)	Restrictions Impacting B.C. Renewable Resources
California	By 2020	39,000	80,800	<ul style="list-style-type: none"> • Require direct connection or dynamic transfer to the California balancing authority for Category 1 producers • Firmed and shaped energy is required for Category 2 producers • Eligibility of B.C.-based run-of-river hydro subject to CEC review
Washington	By 2020	6,000	8,800	<ul style="list-style-type: none"> • Delivery on a real-time basis
Oregon	By 2025	3,500	8,100	<ul style="list-style-type: none"> • Bundled RECs must be U.S.-sourced; unbundled RECs subject to utility cap

2

5.8.3.2 Availability and Cost of B.C. Renewable Resources

3

The market competitiveness analysis in the B&V report was performed assuming that the lowest cost potential resources identified in B.C. are available for export before domestic use.

4

5

6

Chapter 3 of the IRP provides a summary of BC Hydro’s assessment of the resource option potential in B.C. Based on this assessment, [Figure 5-9](#) provides an energy supply curve for identified clean or renewable resources in B.C. The relevant energy price for export purposes is a function of BC Hydro’s domestic energy needs under various load scenarios. For the high incremental load scenarios (Midgap without LNG but including the Fort Nelson load scenario as described in Chapter 2 and the general electrification scenario discussed in Chapter 6), BC Hydro’s energy gap could be about 12,000 GWh⁵² by F2033. Accordingly, the supply curve suggests that renewable resources developed explicitly for export markets would have a firm adjusted unit energy cost (**UEC**) at point of interconnection (i.e., before any transmission-related costs) in excess of \$140/MWh.⁵³

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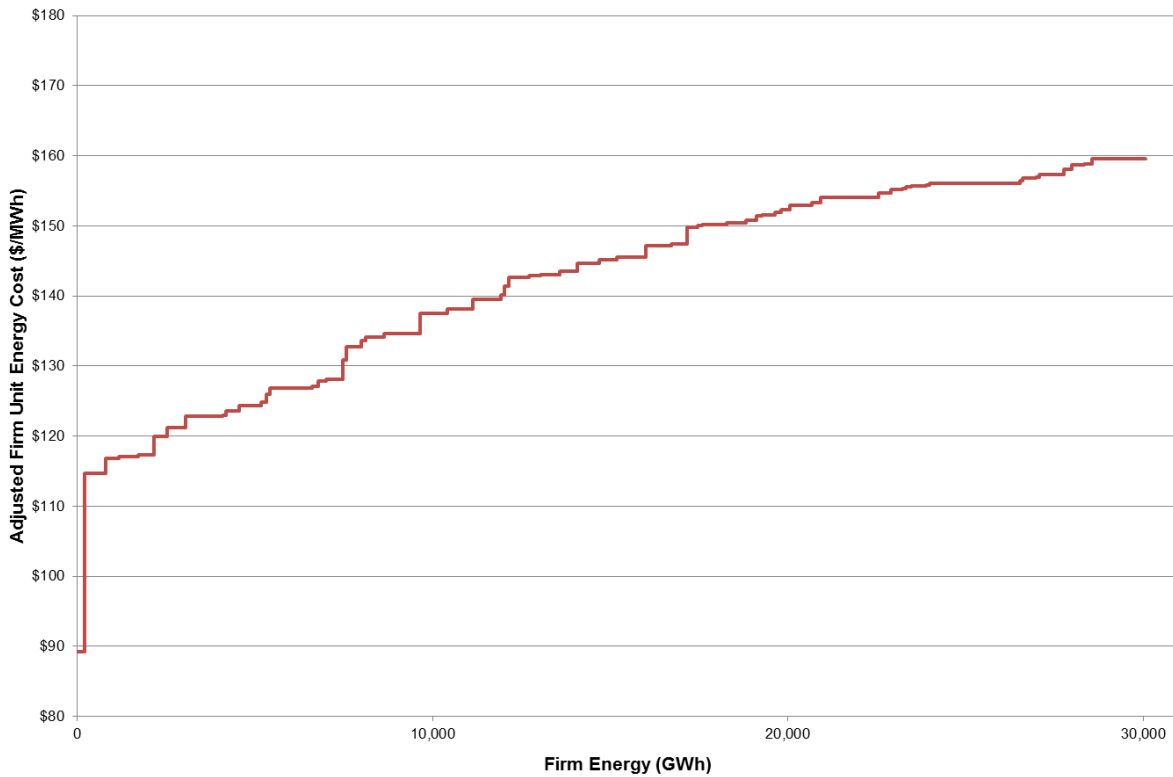
16

⁵² The high incremental load scenario would be higher if renewable energy is used to serve future LNG loads.

⁵³ B&V’s market competitiveness report used BC Hydro resource option data from 2010. Since then the unit energy cost for clean or renewable energy in B.C. has increased.

1
2

Figure 5-9 Supply Curve for Potential Clean Resources in B.C.



3 **5.8.3.3 Transmission Constraints**

4 Transmission capacity from within B.C. to destination markets is required to export
 5 clean energy. Current transmission lines are fully subscribed by firm transmission
 6 rights holders. Furthermore, the availability of non-firm transmission capacity has
 7 been dwindling due to increasing competition from power producers. BC Hydro
 8 expects that it will be able to manage the export of available electricity, however
 9 transmission limits could reduce the economic value received for those exports.

10 **5.8.3.4 Competitiveness of B.C. Resources**

11 The demand for B.C. renewable resources and their relative competitiveness in
 12 export markets can best be ascertained by referring to the “Summary of Findings” in
 13 the B&V report, as follows:

1 Demand for BC resources would increase if: (i) overall demand for
2 renewables in the western interconnection increases or, (ii) the relative
3 competitiveness of BC resources improves. The overall demand may
4 increase if there are changes in one or more market conditions. Similarly,
5 there are a number of factors that could change the relative
6 competitiveness of BC resources.

7 Market Conditions

- 8 • Certain scenarios show that REC prices may increase higher than
9 currently established ACP [Alternative Compliance Payment] levels if
10 either (i) the PTC goes away, (ii) energy prices are relatively low, or
11 (iii) there is a strong RPS demand due to high load growth. In some
12 states, utilities have the option to pay the ACP in lieu of procuring
13 renewable energy or do not have to procure renewable energy if the
14 rate impact limit is exceeded. In order for renewable energy projects to
15 be built under these particular market conditions, there must be strong
16 political will by states to achieve RPS targets at any cost by setting
17 aside ACP caps or rate impact limits.
- 18 • If BC Hydro could demonstrate direct connection to California
19 balancing authorities or be able to dynamically transfer more energy,
20 the province would qualify for a larger market segment, instead of just
21 the firmed/shaped product portion. This could be achieved through
22 building additional transmission capacity or increasing the utilization of
23 existing transmission to the U.S.⁵⁴
- 24 • Limitations on the amount of shaped/firmed products that can be sold
25 into markets like California need to be lifted, though this alone does
26 not determine whether BC projects can be competitive with projects
27 from Washington and Oregon state that are also supplying
28 shaped/firmed products to California.

29 Relative Cost of BC Resources

- 30 • The scenario in which U.S. projects receive no special tax incentives
31 provides a level playing field for BC renewable resources compared to
32 U.S. renewable resources. The ACP caps or rate impact limits
33 currently in many of the RPS states would also need to be lifted or
34 increased.
- 35 • Some higher class resources in Montana and Wyoming appear to be
36 more attractive than wind from BC. Thus, in order for BC resources to

⁵⁴ See subsequent discussion regarding a new transmission line in section [5.8.4.2](#).

1 compete, there needs to be a change in the assumptions about the
2 costs of developing remote resources in Montana and Wyoming. For
3 example, a lack of development of transmission capacity to deliver
4 remote resources to load could make access to the very best
5 resources in Montana and Wyoming more difficult or costly than
6 expected.

- 7 • If the cost for solar PV [photovoltaic] projects after 10 years does not
8 drop as significantly as assumed in the REM model and solar PV
9 projects are not developed to the level modeled, especially in
10 California, this would potentially be of benefit to the competitiveness of
11 BC resources.

12 BC Hydro can try to sell REC-only products, though this market segment
13 is expected to be highly competitive and much lower value, since there is
14 no delivery requirement and it is limited to 10 per cent of the total RPS for
15 California.

16 As for using BC renewables to address the carbon market in the U.S.,
17 there is considerable uncertainty as to how that will play out in the future
18 since carbon markets in the west (including California) are either not well
19 defined (outside of California) or details are still being developed (in
20 California). Alberta will not be an export market for carbon offsets, given
21 restrictions on imported offsets.

22 **5.8.4 Export Activities and Actions**

23 The following section describes a number of BC Hydro and Powerex export-related
24 activities undertaken since the *CEA* was brought into force in 2010. Most of the
25 activities have been terminated or deferred given unfavourable market conditions.

26 **5.8.4.1 Anchor Tenant Transaction with PG&E**

27 Powerex and Pacific Gas & Electric (**PG&E**) held discussions regarding the potential
28 for a sale of approximately 4,000 GWh/year of RPS-eligible energy that would be the
29 anchor transaction for the Canada-Northwest-California (**CNC**) line running from a
30 location near Castlegar in south-eastern B.C. to San Francisco, California. This
31 transaction was abandoned given the changes in California's RPS eligibility as set
32 out by the California Public Utilities Commission and in legislation (Senate
33 Bill 2 (1X)), the current oversupply of RPS eligible renewable supply within the
34 WECC and PG&E's success in procuring in-state RPS eligible resources.

5.8.4.2 New Transmission

1 The CNC transmission line would have allowed 1,500 MW to 3,000 MW of power to
2 flow from B.C. to markets in the south. The CNC line was expected to cost in the
3 \$4 to \$7 billion range and take eight to 10 years to permit and construct. This project
4 was being pursued in partnership with PG&E and Avista Corp. Attempts were made
5 to obtain Bonneville Power Administration to participate in the project but their
6 support was not forthcoming. BC Hydro's approach to developing the CNC line was
7 contingent on the outcome of the anchor-tenant energy transaction with PG&E. In
8 the absence of securing an energy deal, the transmission line becomes a
9 significantly more risky undertaking. As a result, the CNC partners have abandoned
10 the CNC project for the foreseeable future.
11

5.8.4.3 Firming and Shaping Transactions

12 Powerex has been pursuing various firming and shaping transactions to build a
13 portfolio of renewable resources and services and customer relationships to
14 advance its ability to make future sales. These can be stand-alone transactions or
15 transitional sales to the PG&E anchor tenant transaction.
16

5.8.4.4 Low Carbon Energy Sales

17 California continues to push forward on implementing its GHG cap-and-trade
18 program. Powerex has successfully obtained "asset controlling supplier" status from
19 CARB for BC Hydro's portfolio of resources. This results in a much lower carbon
20 intensity for energy delivered into California from BC Hydro's resources compared to
21 "unspecified" resources. Electricity prices in California reflect the price of carbon
22 thereby adding around \$6/MWh to \$7/MWh.⁵⁵
23

⁵⁵ California ISO, DDM Quarterly Report on Market Issues and Performance (May 2013).

5.8.4.5 BC Hydro's Generation Regulation Tariff

BC Hydro is considering a Generation Regulation Tariff which would allow BC Hydro to be compensated for capacity required to respond to moment-to-moment variations in intermittent clean or renewable generation. The design of the tariff would seek to meet market requirements and not negatively impact BC Hydro's ratepayers consistent with the B.C. Government's directions under the *CEA*. Current market conditions have reduced the near-term need to have this tariff in place.

5.8.4.6 Policy Advocacy

BC Hydro and Powerex have been supporting the B.C. Government with its policy advocacy work with California. Consultants were retained to continue to advance B.C. interests regarding resource eligibility within California. Powerex continues to work with the Western Renewable Energy Generation Information System on the registration of renewable resources.

5.8.4.7 Ongoing REC Transactions

Powerex continues to engage in short-term REC transactions in the WECC. These transactions provide experience to understand and influence emerging markets such as the California RPS. Powerex also applied to the CEC to have the Dokie Wind power facility in B.C. certified as "renewable"; this certification is now in place ensuring that energy from this facility is now eligible to be sold in the California RPS market.

5.8.5 Conclusions

Since the enactment of the *CEA*, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term. The reasons include a significant recent increase in renewable energy resources in the WECC, the persistence of tax incentives available to U.S. producers, and the enactment of RPS standards in

- 1 potential markets, particularly California, that exclude many renewable B.C.
- 2 resources.
- 3 [Table 5-8](#) summarizes how the four export-related elements contained in
- 4 Section 3(1)(d) of the *CEA* have been addressed in this section.

1
2

Table 5-8 Meeting CEA’s Export-Related IRP Requirements

Required Section 3(1)(d) Description	How Met in the IRP?
(i) The expected export demand during a defined period	<ul style="list-style-type: none"> • The B&V report identified potential demand for 48,500 GWh to 97,700 GWh of RPS energy in California, Washington and Oregon • Additional carbon market opportunities may exist for B.C. renewable resources to displace GHG-intensive electricity in the U.S. • Access to the RPS and carbon markets in the U.S. is constrained by out-of-state restrictions and energy delivery rules
(ii) The potential for British Columbia to meet that demand	<ul style="list-style-type: none"> • BC Hydro’s resource options assessment identified a large potential for development of clean or renewable resources with an estimated firm UEC cost of at least \$140/MWh at the point of interconnection • Ability to serve U.S. demand is subject to the availability and cost of transmission capacity • Competitiveness of renewable B.C. resources is hampered by eligibility restrictions, U.S. tax incentives and competition from other energy producers in WECC that are closer to the prime U.S. markets
(iii) The actions the authority has taken to seek suitable opportunities for export of electricity from clean or renewable resources	<ul style="list-style-type: none"> • No further export-focused actions are warranted beyond those already taken to date • Conducted anchor tenant discussions with PG&E • Pursued development of CNC transmission line • Pursuing various firming and shaping transactions • Pursuing transactions that would benefit from cap-and-trade programs in California and B.C. • Considering a Generation Regulation Tariff • Supporting Province’s policy advocacy in California • Engaging in short-term REC transactions in WECC to potentially influence emerging RPS markets
(iv) The extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports	<ul style="list-style-type: none"> • BC Hydro pursued contracts for the proposed CNC transmission line and an anchor tenant transaction with PG&E; these initiatives have been abandoned due to changes in RPS eligibility in California and the current oversupply of eligible renewable energy within WECC

3 BC Hydro concludes that, aside from monitoring, there are no actions BC Hydro
 4 should be taking because there are no suitable opportunities for the export of
 5 electricity from clean or renewable B.C. resources for the foreseeable future.

- 1 Consequently, BC Hydro does not perceive, at this time, any value in continuing to
- 2 investigate and develop potential market opportunities for export sales. In response
- 3 to section 3(1)(e) of the *CEA*, current market conditions do not warrant expenditures
- 4 for export, and no expenditures are planned as part of the Recommended Actions.