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Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.

Application for Acceptance of 2019 Consolidated Resource Plan and for Acceptance of Energy Conservation and Innovation (ECI) Portfolio Funding for 2020 to 2022

Decision
and Order G-265-20

October 23, 2020

Before:
A. K. Fung, QC, Panel Chair
C. M. Brewer, Commissioner
R. I. Mason, Commissioner

TABLE OF CONTENTS

Page no.

Executive summary

On October 31, 2019, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)) (collectively, PNG) filed with the British Columbia Utilities Commission (BCUC) an application seeking:

- Acceptance of its 2019 Consolidated Resource Plan; and
- Acceptance of its Energy Conservation and Innovation Portfolio Funding for 2020 to 2022 (ECI Funding Application) (together, the Application)

On December 9, 2019, the BCUC established a written process to review PNG's Application. The British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and the British Columbia Sustainable Energy Association (BCSEA) registered as interveners and participated in the proceeding. The regulatory review process included two rounds of BCUC and intervener written information requests followed by written final and reply arguments.

Pursuant to section 44.1 of the *Utilities Commission Act* (UCA), PNG is required to file a long-term resource plan (LTRP), which includes, among other things, an estimate of demand in the absence of Demand-Side Measures (DSM), a discussion of how the utility intends to reduce demand by taking cost-effective DSM, an estimate of demand after the utility has taken cost-effective DSM and a discussion of the facilities the utility intends to construct or extend to serve its estimated demand. PNG refers to its LTRP as a Consolidated Resource Plan (CRP).

After reviewing the CRP, the BCUC must either accept the plan, if carrying out the plan would be in the public interest, or reject the plan, pursuant to section 44.1(6) of the UCA. In determining whether to accept the CRP, the BCUC must consider British Columbia's energy objectives, the *Clean Energy Act*, cost-effective DSM and the interests of persons in British Columbia.

The Panel examined the evidence and arguments filed in this proceeding, considered whether PNG had met the filing requirements of section 44.1 of the UCA and assessed PNG's 2019 CRP pursuant to the UCA section 44.1(8) considerations. Both interveners expressed support for acceptance of PNG's 2019 CRP. After review, the Panel finds that PNG's 2019 CRP is in the public interest and accepts PNG's 2019 CRP.

Pursuant to section 44.2(1) of the UCA, PNG concurrently filed an expenditure schedule related to DSM expenditures. PNG refers to its DSM expenditure schedule as ECI Portfolio Funding. PNG's ECI Portfolio Funding spans three years, from 2020 to 2022. PNG seeks acceptance of expenditures of $2.278 million to fund an expanded ECI portfolio for the 2020-2022 period, which includes 2020 expenditures of $491,000 in addition to $290,000 requested in its previous ECI funding application and approved by Order G-121-19. The combined request is for an ECI expenditure schedule totalling $2.568 million for the period 2020 to 2022. Additionally, PNG seeks approval to allow for flexibility to reallocate expenditures amongst ECI programs and between years, to record all ECI expenditures in a rate base deferral account, and to amortize all expenditures charged to this deferral account over a period of five years, consistent with the BCUC approvals granted by Order G-121-19.

The BCUC must either accept the schedule, if making the expenditures referred in the schedule would be in the public interest, or reject the schedule, pursuant to section 44.2(3) of the UCA. In determining whether to accept PNG's expenditure schedule, the BCUC considers, among other requirements, British Columbia's energy objectives, the most recent long term resource plan filed by PNG, the *Clean Energy Act*, the cost-effectiveness of the DSM expenditures and the interests of persons in British Columbia who receive or may receive service from PNG.

Both interveners expressed support for acceptance of PNG's ECI expenditure schedule. After reviewing the evidence and arguments related to PNG's ECI Portfolio Funding Application, the Panel determines that PNG's ECI expenditure schedule totalling $2.568 million for the 2020-2022 period is in the public interest and accepts

PNG's ECI expenditure schedule. The Panel also approves certain transfer rules with respect to transfers of funds between ECI program areas and between program years, and approves PNG's proposed continuation of the inclusion of ECI expenditures in a rate base deferral account with amounts in this deferral account to be amortized over a five-year period.

1.0 INTRODUCTION

1.1 Application & Approvals Sought

On October 31, 2019, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)) (collectively, PNG) filed with the British Columbia Utilities Commission (BCUC) an Application for Acceptance of the 2019 Consolidated Resource Plan (2019 Consolidated Resource Plan, 2019 CRP), and for Acceptance of its Energy Conservation and Innovation (ECI) Portfolio Funding for 2020 to 2022 (ECI Funding Application) pursuant to sections 44.1 and 44.2 of the *Utilities Commission Act* (UCA), respectively (together, the Application).

In December 2011, PNG became a wholly owned subsidiary of AltaGas Utility Holdings (Pacific) Inc., a 100 percent owned subsidiary of AltaGas Ltd. Following a corporate restructuring in 2018, AltaGas Utility Holdings (Pacific) Inc. was renamed to AltaGas Canada Inc. (ACI).

On December 19, 2019, the ACI shareholders approved the purchase of the issued and outstanding common shares of ACI by the Public Sector Pension Investment Board (PSPIB) and the Alberta Teachers' Retirement Fund Board in an all cash transaction. The transaction completed on March 31, 2020, whereby PSPIB Cycle Investments, a wholly owned subsidiary of TriSummit Cycle Holding Inc., acquired all outstanding shares of ACI. On completion of the transaction, ACI's name was changed to TriSummit Utilities Inc.[1]

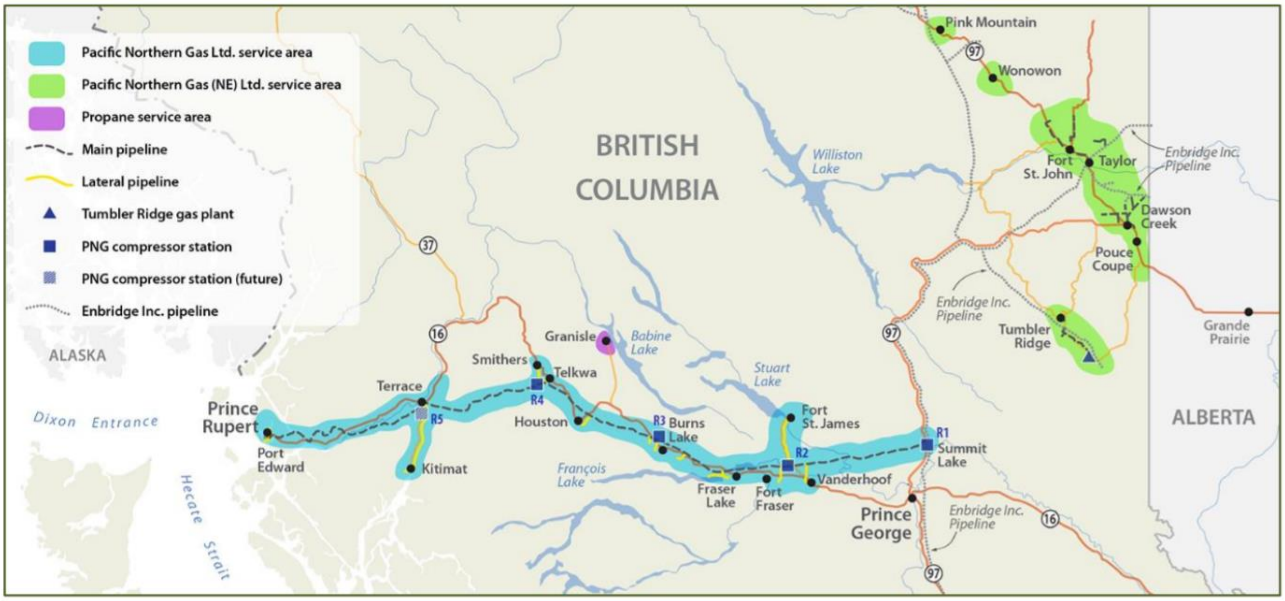
1.1.1 Consolidated Resource Plan

PNG prepared the 2019 Consolidated Resource Plan for its natural gas transmission and distribution system which distributes approximately 4,600 Terajoules (TJ) of natural gas annually to more than 20,400 residential, commercial and industrial customers in North West British Columbia via its PNG-West division (PNG-West). The PNG-West system is located in the western central part of British Columbia, beginning north of Prince George at Summit Lake and extending west to Prince Rupert and Kitimat.

The 2019 CRP also covers three natural gas distribution systems owned and operated by PNG's wholly owned subsidiary, PNG(N.E.), which provides sales and transportation services to approximately 21,000 residential, commercial and industrial customers in Fort St. John, Dawson Creek and Tumbler Ridge, with approximate deliveries of 2,900 TJ, 2,000 TJ and 470 TJ, respectively. The PNG-West and PNG(N.E.) natural gas pipeline systems are illustrated in Figure 1 below[2]:

[1] TriSummit Utilities Press Release dated March 31, 2020 (https://trisummit.ca/index.php/newsroom/227-nvestmentsandompletecquisitionofltaasa20200331093900).
[2] Exhibit B-1, p. 2.

Figure 1:
PNG-West and PNG(N.E.) System Map



PNG states it has forecast its long-term demand to ensure that its pipeline facilities will be sufficient to provide secure and reliable service to its customers over the long term. PNG submits it has developed the 2019 CRP consistent with section 44.1 of the UCA[3] and the BCUC's Resource Planning Guidelines (Guidelines).[4] Further, PNG submits it has identified six key resource planning objectives that form the basis for evaluating potential resources that may be considered in a resource plan, including infrastructure projects, gas supply alternatives and demand side measures.[5] It further submits that it has addressed the BCUC directives issued by Orders G-140-14, related to the 2014 Resource Plan for its PNG-West pipeline system and G-155-15, related to the PNG(N.E.) 2015 Resource Plan.[6]

PNG submits that the 2019 CRP:

- Provides annual and peak day demand forecasts for each of its systems;
- Provides PNG's demand-side measures (DSM) plan, the expenditure schedule associated with its ECI Portfolio and the estimated impact on demand PNG's demand;
- Describes PNG's evaluation of its facilities, system capacity and gas supply resources; and
- Presents the results of PNG's emerging initiatives, Greenhouse Gas (GHG) reduction plans and its customer attitudes survey.[7]

PNG states that the 2019 CRP provides guidance when making prudent decisions on expanding system capacity and in securing a diverse portfolio of supply resources to ensure safe, reliable service at the lowest cost possible.[8]

[3] Exhibit B-1, Cover Letter, p. 1.
[4] https://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.
[5] Exhibit B-1, p. 9.
[6] Exhibit B-1, p. 17.
[7] Exhibit B-1, Cover Letter, pp. 1-2.
[8] Exhibit B-1, Cover Letter, pp. 1-2.

1.1.2 Demand-Side Measures (Energy Conservation and Innovation)

Together with the 2019 CRP, PNG also filed its ECI Funding Application, pursuant to section 44.2 of the UCA. In the ECI Funding Application, PNG is requesting:

- Acceptance of the ECI Expenditure Schedule for the ECI Portfolio for 2020 to 2022;
- Approval to allow flexibility in the reallocation of expenditures among Demand Side Management (DSM) programs and between program years, subject to the total amount not exceeding the total amount of $2,278,000, as per the 2020-2022 ECI Expenditure Schedule; and
- Approval to continue recording all ECI expenditures in a rate base regulatory asset deferral account, with an amortization period of five years for all expenditures charged to this regulatory asset deferral account.[9]

1.2 Previous Resource Plans and BCUC Directives

By Order G-140-14, the BCUC accepted PNG's 2014 Resource Plan for its PNG-West pipeline system (PNG-West 2014 Resource Plan).

Subsequent to PNG's filing of its 2015 PNG (N.E.) Resource Plan, the BCUC also accepted PNG's proposal to submit the PNG-West and PNG(N.E.) Resource Plans on a consolidated basis and to reduce the filing frequency to every five years. PNG was directed to file its subsequent consolidated resource plan by no later than April 8, 2019.[10] By Order G-155-15, the BCUC accepted the PNG(N.E.) 2015 Resource Plan and confirmed the filing date of PNG's Consolidated Resource Plan of April 8, 2019.

In accepting the PNG-West 2014 and PNG(N.E.) 2015 Resource Plans, respectively, the BCUC also provided a number of directives and required PNG to include certain information in its subsequent resource plans. PNG states that the 2019 CRP addresses the BCUC's directives and, in Table 2 of the 2019 CRP, sets out PNG's responses to each directive.[11] This table, including the sections in the decision where these directives are discussed, are included in Appendix A to this decision.

On September 26, 2019, the BCUC approved PNG's extension request to file its 2019 CRP by October 31, 2019.[12]

1.3 Regulatory Process

On December 9, 2019, the BCUC established a written public hearing process and a regulatory timetable for review of PNG's Application.[13] The regulatory timetable consisted of intervener registration, BCUC and intervener information requests (IRs), submission on further process, with further process to be determined.

By January 17, 2020, British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and British Columbia Sustainable Energy Association (BCSEA) had registered as interveners. FortisBC Energy Inc. registered as an interested party in the proceeding.

A letter of comment, dated February 18, 2020, was also submitted by the Chairman of the TC Water Committee, Council of Canadian Terrace Chapter and BC Federation of Fly Fishers, which expressed concerns about a matter that is not at issue in this proceeding. The Panel therefore does not consider this letter in its decision.

[9] Exhibit B-1, Cover Letter, pp. 3-4.
[10] Order G-140-14.
[11] Exhibit B-1, pp. 18-22.
[12] Orders G-76-19 and G-233-19.
[13] Order G-322-19.

The Panel amended the regulatory timetable to allow PNG additional time to respond to IRs, and subsequently to allow for a second round of IRs.[14]

PNG filed its final written argument on June 11, 2020, with intervener final arguments filed on June 25, 2020. PNG filed its reply argument on July 2, 2020.[15]

1.4 Decision Framework

As noted, PNG's Application consists of two distinct components, namely, the 2019 CRP and the ECI Funding Application.

Given that each application is filed and reviewed under separate provisions of the UCA, the Panel considers each component separately against the relevant legislative framework. With respect to the acceptance of the 2019 CRP, in Section 2 of this decision the Panel considers the following questions:

- Has PNG met the filing requirements of section 44.1(2) of the UCA?
- Do the section 44.1(8) UCA considerations support acceptance?
- Is the 2019 CRP in the public interest?

The Panel discusses and makes determinations on specific topics arising out of PNG's 2019 CRP in sections 2.3 to 2.5. The Panel provides an overall determination on acceptance of PNG's 2019 CRP in section 2.6.

As for the ECI Funding Application, the Panel considers the following questions in Section 3 of this decision:

- Do the section 44.2(5) UCA considerations support acceptance?
- Is PNG's 2020-2022 ECI Expenditure Schedule in the public interest?

Unlike the 2019 CRP, PNG's ECI Funding Application also seeks specific approvals of certain ECI expenditures, allocation and accounting treatment. The Panel addresses these requests in section 3.1. The Panel then discusses the ECI Funding Application and makes determinations on these requests and acceptance of the ECI Funding Application in sections 3.5 to 3.7.

2.0 PNG's 2019 Consolidated Resource Plan

2.1 Approvals Sought

PNG submits that the 2019 CRP meets the adequacy requirements of section 44.1(2) of the UCA and has been prepared in accordance with the Guidelines, aligns with British Columbia's energy objectives pursuant to section 44.1(8) of the UCA, and is in the public interest.[16]

PNG requests acceptance of the 2019 CRP under section 44.1(6) of the UCA and is not seeking approval of any specific elements of the long-term resource plan.[17]

2.2 Legislative Framework

PNG has filed its 2019 CRP pursuant to section 44.1(2) of the UCA, which requires that a utility must file a long-term resource plan with the BCUC. Section 44.1(2) provides that the resource plan must include all of the following:

[14] Orders G-24-20 and G-72-20.
[15] Order G-122-20.
[16] Exhibit B-1, Cover Letter, pp. 1-2.
[17] Exhibit B-1, Cover Letter, pp. 1-2.

(a) An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and

(g) Any other information required by the BCUC.

Pursuant to sections 44.1(6) and (7) of the UCA, if the BCUC determines that carrying out the plan would be in the public interest, it must accept PNG's 2019 CRP, or if it determines otherwise, it may reject the plan, or a part thereof. If part of the 2019 CRP is rejected, PNG may resubmit that part within the specified timeframe.[18]

Acceptance of the 2019 Consolidated Resource Plan

In determining whether to accept PNG's 2019 CRP, the Panel must consider the requirements set out in sections 44.1(8)(a), (c) and (d) of the UCA, specifically:

(a) The applicable of British Columbia's energy objectives;

(c) Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and

(d) The interests of persons in British Columbia who receive or may receive service from the public utility.

Section 44.1(8)(b) of the UCA requires the BCUC to examine the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (CEA). However, as noted previously in BCUC decisions,[19] sections 6 and 19 of the CEA apply only to electric utilities and are therefore not relevant to this decision as PNG is a natural gas public utility.

2.3 Has PNG met the filing requirements of Section 44.1(2) of the UCA?

In this section, the Panel provides an overview of PNG's 2019 CRP over the 2018-2038 planning period (Planning Period). The Panel then discusses whether the 2019 CRP provides the necessary context and analysis, and whether PNG's 2019 CRP satisfies each of the filing requirements as set out in section 44.1(2) of the UCA, namely:

i. Estimate of demand in the absence of new demand side measures – section 44.1(2)(a);

ii. Energy demand taking into consideration new cost-effective demand-side measures – sections 44.1(2)(b), (c) and (f);

iii. Facilities – section 44.1(2)(d);

[18] Section 44.1(7)(a) of the UCA.
[19] For example, G-14-11, p. 16.

iv. Energy purchases – section 44.1(2)(e); and

v. Other information required by the BCUC – section 44.1(2)(g).

2.3.1 Estimate of Demand

Pursuant to section 44.1(2)(a) of the UCA, PNG must file a long term resource plan which includes "an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan."[20] PNG explains its methodology for developing its demand estimate in the following terms:

> PNG has developed a long-term (20) year gross demand forecast for each of its four distribution systems based on its knowledge of its service territories and economic outlook over the planning period. The demand forecast is developed from projections of base load and temperature sensitive deliveries over the 20-year planning period. Section 7 of this Resource Plan summarizes the expected demands on the system. A summary of the 20-year planning model used to determine the gross demand forecasts is presented in the Appendices.[21]

2.3.1.1 Gross Annual Demand Forecast

In its 2019 CRP, PNG provides a gross annual demand forecast for each service area by customer class up to 2038. The gross demand forecast is an aggregation of the demand forecasts developed for the sales and transportation customer classes as well as for company use gas.[22]

PNG submits that, as it operates four distinct distribution systems in four service territories, a consolidated demand forecast does not provide any additional insight into PNG's operations and challenges over the forecasting period. PNG submits that a consolidated demand forecast is relevant when designing its annual gas supply portfolio and PNG routinely files such a consolidated demand forecast when filing its Annual Gas Contracting Plan (ACP) with the BCUC.[23]

In Figures 43 to 46, attached as Appendix B to this decision,[24] PNG presents the historical and forecast gross annual demand over the Planning Period for each customer class for each of its four service areas (PNG-West, Fort St. John, Dawson Creek and Tumbler Ridge). Over the Planning Period, PNG anticipates a year-on-year decrease in annual demand, primarily due to a decrease in residential customer demand.[25]

While PNG forecasts a stable demand for the large customer sectors, this is offset by the forecast gradual loss of the residential and small commercial market demand over the Planning Period.[26]

PNG states that the following factors are expected to influence demand for natural gas over the forecast period:

- population growth;
- construction trends, including change in residential building mix and penetration of electric space heat;
- residential energy efficiency retrofits; and

[20] Section 44.1(2)(a) of the UCA.
[21] Exhibit B-1, p. 8.
[22] Exhibit B-1, Section 7.3.6, p. 106.
[23] Exhibit B-5, BCSEA IR 21.1, pdf. p. 40.
[24] Exhibit B-1, Section 7.3.6, pp.107-108.
[25] Exhibit B-1, Section 7.3.6, pp.107-108.
[26] Exhibit B-1, Section 9.5, p. 106.

- the British Columbia Government's Clean Growth Strategy program for industry (CleanBC Program for Industry).[27]

Residential and Small Commercial Customer Demand

PNG's residential customer demand forecast is based on two key variables: (i) a forecast of the residential customer additions; and (ii) a residential end-use model that predicts the average residential use per account (UPA), which is based on a residential end-use survey (REUS) which collects information on a number of factors including the dwelling type, construction, the number and type of gas appliances in the home and the behaviour of residents.[28]

To develop forecasts of residential customer additions for each year of the forecast period, PNG begins with a forecast of household formations in the local health regions and applies the forecast rate of growth in households to PNG's residential customer count. PNG then applies a region-specific capture rate to determine the forecast customer additions.[29]

PNG explains that the capture rates are based on a comparison of housing starts and actual customer additions in each region over the past five years, consistent with the method described in the PNG(N.E.) 2015 Resource Plan.[30] However, PNG states that this method is only applicable in cases where customer additions are significantly greater than customer losses. This has not been the case in PNG-West, which experienced a net loss of customers over the past five and ten years, and a small net gain over the past three years.[31] Further, PNG states that the very low level of building activity in Tumbler Ridge does not accurately reflect customer capture rates in that region.[32]

PNG states that in the 2019 CRP demand forecast, it has reduced capture rates developed in the PNG-West 2014 and PNG(N.E) 2015 Resource Plans by 10 percent to reflect that actual customer additions have generally been lower than those forecast in the PNG-West 2014 and PNG(N.E) 2015 Resource Plans. As a refinement to its customer additions forecast, PNG explains that it has implemented a capture rate that declines over the forecast period to reflect the impact of the CleanBC Plan,[33] namely, an expectation of an increased rate of decline in customer demand.

As shown in Table 22,[34] PNG has applied a 15 percent decrease in capture rates for PNG-West (West),[35] Fort St. John, Dawson Creek and Tumbler Ridge and a 21 percent decrease for PNG-West (East) by 2038.[36]

[27] Exhibit B-1, Section 7.2, pp. 77-81.
[28] Exhibit B-1, p. 73.
[29] Exhibit B-1, Section 7.3.1.1, pp. 81-82.
[30] Exhibit B-1, Section 7.3.1.1, p. 82.
[31] Exhibit B-3, BCUC IR 26.2.
[32] Exhibit B-1, Section 7.3.1.1, p. 82.
[33] CleanBC Plan, https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf.
[34] Exhibit B-1, Section 7.3.1.1, p. 83.
[35] Exhibit B-3, BCUC IR 16.3. The PNG-West (West) region is defined as that part of the PNG-West service area that includes the communities of Prince Rupert, Port Edward, Kitimat, Terrace and Thornhill.
[36] Exhibit B-3, BCUC IR 16.3. The PNG-West (East) region is defined as that part of the PNG-West service area that lies east of Terrace/Thornhill and includes the communities of Smithers, Houston, Vanderhoof, Fort St. James and Burns Lake.

Table 22: New residential customer capture rates over forecast period

Residential	Capture Rates (Reference Case)		
	2020	2029	2038
PNG-West (West)	65%	57%	50%
PNG-West (East)	90%	79%	69%
FSJ/DC	90%	82%	75%
Tumbler Ridge	90%	82%	75%

PNG states it last undertook a REUS in 2013 and a commercial survey in 2015. In an effort to improve its residential demand forecasts, PNG states that in January 2019, it commissioned and completed a Customer Attitudes Survey which targeted a sample of residential and commercial customers from across all divisions. This included collecting information on space heating; the fuel used for heating domestic hot water; and the residential housing mix.[37] According to PNG, the Customer Attitudes Survey:

> …addressed a range of topics including attitudes and beliefs about the environment, natural gas and renewable energy; satisfaction with customer service interactions; interest in online services from PNG; participation and interest in energy-efficiency initiatives, and willingness-to-purchase natural gas augmented with biomethane. A set of questions on customers natural gas appliances and dwelling characteristics, similar to those included in the 2013 REUS, were included as well.[38]

PNG submits that the survey results were used to augment and update the information obtained from the 2013 REUS and 2015 commercial survey, which, together with billing records of historical energy consumption, were used to arrive at its gross residential and commercial demand forecast for the proposed long-term resource plan.[39]

PNG submits that the following analyses support the continued validity of its residential end use forecasting model based on the results of the 2013 REUS:[40]

> PNG has compared the actual UPA of its residential customers in 2018 with the UPA forecast for 2018 in the 2014 and 2015 Resource Plans for PNG-West and PNG (NE), respectively. Actual residential UPA in PNG-West and Fort St. John is approximately four percent lower than forecast, while in Dawson Creek the 2018 actual UPA matches the forecast UPA. In Tumbler Ridge, which has a small customer base that is more susceptible to changes in occupancy of even a smaller number of dwellings, the actual UPA in 2018 was within 8 percent of the forecast UPA.

PNG concludes that a residential UPA forecasting error of less than five percent in all PNG divisions, with the exception of Tumbler Ridge, supports the continued validity of the current residential UPA forecasting model. Further, it suggests that no fundamental change has occurred in residential customers' natural gas consumption since the completion of the 2013 REUS.[41]

Taking into account these factors, PNG submits it has maintained its "practical approach to forecasting residential and commercial demand, and made a small yet meaningful adjustment to the capture rates over time to reflect PNG's view that the policies identified in the CleanBC Plan, especially the focus on the

[37] PNG Final Argument, p. 2.
[38] Exhibit B-1, p. 20, Table 2.
[39] Exhibit B-1, p. 8.
[40] PNG Final Argument, para. 6, p. 2.
[41] PNG Final Argument, para. 6, p. 2.

electrification of space heating load, are expected to change the penetration of natural gas in serving new loads."[42]

In PNG's view, any improvement to its residential end-use model that would result from an update of the 2013 REUS would not justify the additional effort and cost, which is estimated to be between $125,000 and $150,000.[43] Instead, PNG proposes to "update its REUS when, in its estimation, the behaviour of its residential customers, in regards to natural gas use, has changed significantly."[44] PNG further notes that it has responded to many IRs to clarify understanding of the demand forecasts and no material issues have been identified which would warrant any changes in its forecast methodology or the demand forecasts presented in the Application.[45]

With respect to the anticipated effect of the CleanBC Plan on reducing the use of natural gas in new construction to achieve its goal of net zero ready efficiencies, PNG states it has "forecast the UPA of new construction to decline by 20 percent by 2025, by 40 percent by 2027, and by 80 percent by 2032."[46]

Small Commercial Customer Demand

PNG defines small commercial customers as commercial customers that consume less than 5,500 GJ per year.[47]

Consistent with the approach taken in earlier long-term resource plans, PNG explains that it assumes the trend in household formations is a proxy for growth in small commercial customer additions. PNG states that the capture rates adopted for the demand forecasts for 2020 in all regions are the same as those used in the PNG-West 2014 and PNG(N.E) 2015 Resource Plans, respectively.[48]

PNG states that it is forecasting a decline in commercial capture rates over the Planning Period to reflect the impact of the CleanBC Plan, namely an increased focus on the electrification of space heating. The decline in capture rates is expected to be slightly more pronounced in PNG-West owing to the higher delivered cost of natural gas and perceptions of the relative costs of electricity and natural gas.[49]

As shown in Table 24,[50] PNG has applied an 11 percent decrease in capture rates for PNG-West (West) and PNG-West (East) and a 9 percent decrease for Fort St. John, Dawson Creek and Tumbler Ridge by 2038.[51]

Table 24: New commercial customer capture rates over forecast period

Commercial	Capture Rates (Reference Case)		
	2020	2029	2038
PNG-West (West)	85%	79%	74%
PNG-West (East)	85%	79%	74%
FSJ/DC	100%	95%	91%
Tumbler Ridge	100%	95%	91%

PNG states it has applied the decline in capture rates of small commercial customers to its small commercial demand forecast. PNG explains that this is a refinement of the forecasting method used in both the PNG-West

[42] PNG Final Argument, para. 8, p. 3.
[43] Exhibit B-3, BCUC IR 1.25.7; Exhibit B-7, BCUC IR 2.60.1; BCSEA Final Argument, para. 62, p. 16; BCOAPO Final Argument, p. 4.
[44] Exhibit B-5, BCSEA IR 19.3, pdf p. 38.
[45] Ibid., para. 11, p. 4.
[46] Exhibit B-1, p. 88.
[47] Exhibit B-1, Section 7.3.2, p. 90.
[48] Exhibit B-1, Section 7.3.2.1, p. 91.
[49] Exhibit B-1, Section 7.3.2.1, p. 91.
[50] Exhibit B-1, Section 7.3.2.1, p. 91.
[51] Exhibit B-1, Section 7.3.2.1, p. 91.

2014 and PNG(N.E.) 2015 Resource Plans which did not reflect any changes over time in commercial customers' preferences regarding natural gas as a source for space and domestic water heating.

Similar to its residential demand, PNG submits that it has maintained a practical approach to forecasting commercial demand, and made a small yet meaningful adjustment to the capture rates over time to reflect PNG's view that the policies identified in the CleanBC Plan, especially the focus on the electrification of space heating load, are expected to change the penetration of natural gas in serving new commercial loads.[52]

Positions of the parties

BCSEA considers that PNG's gross residential demand forecast is sufficiently accurate for the current planning purposes, noting that the forecast reflects the anticipated effect of the CleanBC Plan.[53]

BCOAPO expresses concerns regarding the continued use of the 2013 REUS for future applications. BCOAPO states that it accepts PNG's evidence that the forecast UPAs from the 2013 REUS were adequate for 2018 overall, but it notes that "while it is possible that partially offsetting changes in the UPA drivers have occurred since then, keeping estimates close to actuals; there is no guarantee that they will offset in future."[54]

BCOAPO recommends that a REUS update be conducted once every 10 years, even if only to confirm a past trend is continuing to inform projections with as accurate a picture as possible. BCOAPO further submits that PNG should indicate the type of data that would "strongly suggest an update to the REUS was advisable" so as to provide parties with a "greater understanding of the threshold PNG is setting before it will, on its own motion, update its REUS."[55]

PNG Reply Submission

In support of the continued validity of the 2013 REUS to forecast demand, PNG points out that:[56]

> Information on residential behaviour and dwelling characteristics provided through the REUS informs the residential end-use forecast. Currently, the accuracy of the 2014 residential use per account (UPA) forecast for 2018 for the PNG-West, Fort St. John and Dawson Creek systems that, collectively, comprise 97 percent of residential customers, is approximately four percent. The residential demand forecast is determined as the product of the residential UPA and the forecast number of customers; only the first factor is determined using the results of the REUS. Furthermore, the demand from the residential sector comprises only 30 percent of the entire demand on PNG's systems. Therefore, even significant deviation in the forecast UPA has a diluted effect on the demand forecast of the overall system. In light of these considerations, PNG submits that the 2013 REUS continues to be representative of residential customers' characteristics and behaviours in regard to natural gas use.

PNG submits that a "trend of significant deviation between the forecast and actual UPA would likely prompt a revision to PNG's residential end-use model, and for PNG to undertake a new REUS" and is amenable to BCOAPO's recommendation to update the REUS every 10 years, which PNG considers to be a reasonable recommendation. PNG therefore proposes to update the REUS in 2023.[57]

Panel Determination

In 2015, the BCUC directed PNG(N.E.) to include a summary of the assessments performed and the assessment results that PNG relied on to inform the timing of the REUS and small commercial customer survey in the next

[52] Exhibit B-3, BCUC 16.4.
[53] Exhibit B-3, BCUC 16.4; BCSEA Final Argument, para. 61, pp. 15-16.
[54] BCOAPO Final Argument, p. 4.
[55] BCOAPO Final Argument, pp. 4-5.
[56] PNG Reply Argument, para.8, pp. 2-3.
[57] PNG Reply Argument, para. 9, p. 3.

resource plan[58]. Notwithstanding that direction, PNG indicates that it decided not to refresh the results of the entire 2013 REUS in the absence of any evidence that the year over year trend of its residential and small commercial use per account, customer characteristic or end use behaviour has changed substantially since 2013.[59] The absence of a refresh of the 2013 REUS leaves the Panel with little evidence that the assumptions underlying the 2013 REUS remain valid, seven years after the completion of the REUS.

Nonetheless, the Panel has considered the cost savings of some $75,000 to $100,000 achieved through conducting a Customer Attitudes Survey rather than updating the REUS, PNG's willingness to update the REUS in 2023 and the relatively minor variances between forecast and actual demand to date.[60] With these considerations in mind, the Panel accepts that PNG's 2013 REUS, together with PNG's 2015 commercial survey and 2019 residential and commercial Customer Attitudes Survey results, provide a reasonable basis for its residential and small commercial customer demand estimate for the Planning Period.

Despite accepting the basis for the estimated demand, the Panel considers the REUS to be an important tool for planning and is concerned that PNG did not follow the BCUC's 2015 direction. The Panel accepts the positions of both BCOAPO and PNG that it would be reasonable and timely for PNG to update the REUS in 2023 given that 10 years will have passed since the 2013 REUS. Accordingly, **the Panel directs PNG to update the REUS no later than 2023 and include the results of the updated REUS in the demand forecast in its next long-term resource plan.**

Large Customer Demand

In the 2019 CRP, PNG provides a regional economic outlook for its service areas, including commercial and industrial developments.[61] PNG explains that economic growth in the region is highly dependent on both the likelihood and timing of major resource development investments.[62] PNG states that the identification of large projects in the regions in which PNG-West or PNG(N.E.) operates is intended to provide an overview of the economic activity either occurring or potentially occurring. However, PNG does not expect that many of these projects will become customers of PNG.[63]

PNG classifies its large customers as either Large Commercial, Industrial, Seasonal or Natural Gas Vehicle (NGV) fleets. Large customers account for approximately one half of PNG's annual demand on its consolidated system.[64]

PNG bases its long-term large customer demand forecast on each customer's demand forecast for the coming year, a review of actual deliveries, and any anticipated changes in use as gathered from customer discussions. PNG explains that it has held the 2020 demand forecast provided for each large customer constant over the Planning Period unless PNG is aware of reasonably foreseeable changes to a customer's demand.[65] In cases where a customer's forecast differs from its historical demand, and no changes in the customer's plant, equipment or operations are anticipated, PNG explains that it may, after discussions with the customer, adjust the customer-provided forecast to more closely reflect historical operations.[66]

PNG states that at this time, it has no information that would suggest changes to the number and type of large customers over the Planning Period.[67]

[58] Order G-155-15.
[59] Exhibit B-1, page 20, Table 2.
[60] Exhibit B-3, BCUC IR 25.7, pdf p.84; BCSEA Final Argument, para. 62, p. 16.
[61] Exhibit B-1, Section 2.2.2, p. 36.
[62] Exhibit B-1, Section 2.2.2, p. 36.
[63] Exhibit B-3, BCUC IR 6.2.
[64] Exhibit B-1, Section 7.3.3, p. 97.
[65] Exhibit B-3, BCUC IR 18.1.1.
[66] Exhibit B-3, BCUC IR 18.2.
[67] Exhibit B-1, Section 7.3.3, p. 97.

PNG expects the large customer demand to remain relatively stable over the Planning Period, with some variation in the demand for Large Commercial and Industrial customer classes, which is discussed in more detail in the following sections.[68]

Large Commercial Customers

PNG defines large commercial customers as customers that consume more than 5,500 GJ per year. Examples include hospitals, shopping centers and swimming pools that use natural gas for their space heating requirements.[69]

PNG's large commercial customer forecast for the PNG-West service area includes a demand forecast from LNG Canada, which has made a request for PNG to provide natural gas service primarily for a workforce accommodation centre and construction facilities during the LNG Canada project construction phase, that is expected to last for some 5 to 10 years.[70] PNG states that deliveries are expected to begin in the fourth quarter of 2019, increasing in the fourth quarter of 2020, and reaching an estimated demand of 600 TJ for 2021 through to 2024.[71]

In addition, the large commercial demand forecast reflects a request made by LNG Canada for natural gas service to its new non-process related facilities. PNG's demand forecast assumes service will commence in 2021 and continue for the 20+ year life of the LNG Canada project.[72]

The large commercial demand forecast for the Fort St. John service area includes the supply of natural gas to the temporary work camp for the British Columbia Hydro and Power Authority (BC Hydro) Site C dam project, which is expected to continue to the end of 2024.[73]

PNG does not forecast any new large commercial customers for the Tumbler Ridge and Dawson Creek service areas.[74]

Industrial Customers

The demand forecast for industrial customers in the PNG-West service area is expected to increase by more than 500 TJ annually, beginning in 2020, as a result of three new customers,[75] specifically: AltaGas Ltd.'s Ridley Island Propane Export Terminal (RIPET); Skeena Bioenergy Ltd.'s pellet plant; and Pembina's Watson Island Propane Terminal.[76]

In the Fort St. John service area, PNG's industrial demand comprises mainly natural gas production facilities and oil and gas services.[77] PNG explains that fuel gas loads in oil and gas operations are typically consumed by compressors, line heaters and space heating.[78] However, as a result of federal and provincial initiatives, such as the Clean Fuel Standard [79]and the CleanBC Plan,[80] PNG anticipates that a portion of this load will be lost as

[68] Exhibit B-1, Section 7.3.3, p. 98.
[69] Exhibit B-1, Section 7.3.3.1, p. 98.
[70] Exhibit B-1, Section 7.3.3.1, p. 98.
[71] Exhibit B-1, Section 7.3.3.1, p. 98.
[72] Exhibit B-1, Section 7.3.3.1, p. 99.
[73] Exhibit B-1, Section 7.3.3.1, p. 99.
[74] Exhibit B-1, Section 7.3.3.1, p. 99.
[75] Exhibit B-1, Section 7.3.3.2, p. 100.
[76] Exhibit B-1, Section 7.3.3.2, pp. 100-101.
[77] Exhibit B-1, Section 7.3.3.2, p. 101.
[78] Exhibit B-1, Section 7.3.3.2, p. 101.
[79] Exhibit B-1, Section 2.1.1, p. 23.
[80] Exhibit B-1, Section 2.1.1, p. 26.

producers convert their field compressors to electric drive units. PNG has reflected a loss of 60 percent of the compressor fuel gas load in the demand forecast by 2030.[81]

In the Dawson Creek service area, PNG states that industrial demand is dominated by the regional Liquefied Natural Gas (LNG) facility owned by Campus Energy which accounted for almost two thirds of the small industrial throughput in 2018. [82]

PNG's industrial demand in the Tumbler Ridge service area is dominated primarily by Canadian Natural Resources Ltd.'s (CNRL) Murray River operations.[83] PNG states that CNRL intends to ramp up its Murray River facility and Speaker plant production to full capacity during the latter part of 2019, and it is restarting production from its low pressure wells in Murray River which requires an increase in compression and fuel gas.[84] As a result, demand for fuel gas from CNRL Murray River is expected to return to historical levels of 550 to 750 TJ per year by 2020.[85]

PNG states that opportunities for CNRL to electrify its Murray River fuel loads are limited by the lack of proximity to the BC Hydro grid in all but the northern extent of the production area.[86] PNG states that British Columbia's electrification policies are expected to reduce the demand from CNRL Murray River by 10 to 15 percent of existing demand. However, this reduction in demand is expected to be offset by increased demand from additional production in the area.[87] Accordingly, PNG has maintained the 2020 forecast demand from CNRL Murray River constant over the Planning Period.[88]

Positions of the Parties

BCSEA states that is does not take issue with PNG's gross demand forecast for large customers, which results from methods previously accepted by the BCUC.[89]

Planning Scenarios

In the 2019 CRP, PNG provides an overview of the federal and provincial policies and initiatives that could impact PNG and its customers over the Planning Period. Examples include the Clean Fuel Standard, Appliances and Equipment Standards, the CleanBC Plan, the CleanBC Program for Industry, and *the Greenhouse Gas Reduction (Emissions Standards) Statutes Act.*[90]

PNG identified four CleanBC Plan policies that are assumed to impact the forecast demand by 2030:

i. The impact of building energy retrofits on the residential and commercial sectors;

ii. Increased efficiency of new construction in the residential and commercial sectors;

iii. An increased penetration of electricity for space heating and domestic hot water heating in the in the [sic] residential and commercial sectors; and

iv. Electrification of industry, particularly of the upstream oil and gas industry.[91]

[81] Exhibit B-1, Section 7.3.3.2, p. 101.
[82] Exhibit B-1, Section 7.3.3.2, p. 102.
[83] Exhibit B-1, Section 7.3.3.2, p. 103.
[84] Exhibit B-1, Section 7.3.3.2, p. 103.
[85] Exhibit B-1, Section 7.3.3.2, p. 103.
[86] Exhibit B-1, Section 7.3.3.2, p. 103.
[87] Exhibit B-1, Section 7.3.3.2, pp. 103-104.
[88] Exhibit B-1, Section 7.3.3.2, p. 104.
[89] BCSEA Final Argument, para. 63, p. 16.
[90] Exhibit B-1, Section 2.1, pp. 23-32.
[91] Exhibit B-7, BCUC IR 58.1.

The impact of the CleanBC Plan on each service area's load varies based on the relative demand of the residential and commercial sectors, compared to the total demand on each system. For example, PNG submits the electrification of the upstream oil and gas industry is only expected to impact demand on the Fort St. John system.[92]

By Order G-140-14, the BCUC directed PNG to include sensitivity analysis scenarios incorporating the gain or loss of a large commercial or industrial customer in its next resource plan.

PNG states that due to the networked nature of its distribution systems, there are many possible outcomes when a large customer requests service. While PNG has included a sensitivity analysis of its demand forecast that reflects possible alternative forecasts of known large customer demand in section 7.4 of its 2019 CRP, PNG states it has not assigned an "arbitrary level of future demand to an unknown large customer."[93]

PNG states it has prepared a gross demand forecast which reflects PNG's opinion regarding the most likely growth in demand over the Planning Period, which forms the Reference Scenario. PNG also developed alternative demand scenarios to provide the sensitivity of demand forecasts to changes in economic and climatic conditions to provide a range of expected demands.[94] PNG presents three planning scenarios in its 2019 CRP: Reference Scenario, Competitive Gas Scenario and Competitive Electric Scenario.

Reference Scenario

The Reference Scenario forms the basis of the planning scenarios and represents PNG's gross demand forecast. PNG explains that the Reference Scenario reflects the current mix of natural gas appliances and insulation in existing construction, and the current mix of Single-Family Dwellings and Multi-Family Dwellings being constructed in PNG's service areas.[95]

UPA forecasts for residential and commercial construction reflect changes to the mix of new construction as well as improvements to the energy efficiency of new construction, and building retrofits that are aligned with the policy actions and targets identified in the CleanBC Plan.[96] Forecast changes to large customers' loads are based on known additions and removals of these loads as well as on an estimated response to the CleanBC Plan to promote the electrification of the upstream oil and gas sector.[97]

Competitive Gas Scenario

Under the Competitive Gas scenario, PNG states that the negative perceptions of natural gas as a fossil fuel "take a back seat" to value placed on the cost competitive benefit of natural gas as compared to electricity for thermal applications.[98] Accordingly, capture rates for new residential and commercial customers stabilize at current levels over the Planning Period, and the penetration of natural gas furnaces in new construction increases and remains stable over the Planning Period.[99]

Under the Competitive Gas scenario, residential construction shows a higher preference for Single Family Dwellings than under the Reference Scenario.[100] Further, improvements to the energy efficiency of new construction are half of those targeted under the CleanBC Plan, while no significant improvements to the energy

[92] Exhibit B-7, BCUC IR 58.1.
[93] Exhibit B-1, Section 1.5, p. 19.
[94] Exhibit B-1, Section 7.1, p. 77.
[95] Exhibit B-1, Section 7.4, p. 110.
[96] Exhibit B-1, Section 7.4, p. 110.
[97] Exhibit B-1, Section 7.4, p. 110.
[98] Exhibit B-1, Section 7.4.1, p. 112.
[99] Exhibit B-1, Section 7.4.1, p. 112.
[100] Exhibit B-1, Section 7.4.1, p. 112.

efficiency of building retrofits are reflected.[101] PNG does not elaborate as to how it established the assumption that improvements to the energy efficiency of new construction would be half of those targeted under the CleanBC Plan, stating that it has developed the scenarios to present a range of demand forecasts that could plausibly be expected, depending on how public policies, particularly the CleanBC Plan, are enacted into regulation and law.[102]

Under the Competitive Gas scenario and with respect to large customer demand, PNG forecasts natural gas demand from Skeena BioEnergy Ltd.'s pellet plant to increase to 120 TJ per year beginning in 2022.[103] In the Fort St. John Service area, PNG has reflected no reduction in compressor fuel gas load as a result of federal and provincial incentives.[104] Further, PNG assumes that deliveries to the LNG Canada temporary construction facilities are extended an additional five years, to 2028, consistent with LNG Canada making a positive final investment decision on constructing a second liquefaction train.[105]

Competitive Electric Scenario

The Competitive Electric scenario reflects the loss of natural gas' market share to electricity. PNG states that capture rates for new residential and commercial customers decline faster than under the Reference Scenario, and the penetration of natural gas furnaces in new construction is lower and declines faster over the Planning Period compared to the Reference scenario.[106] Under this scenario, residential construction shows a lower preference for Single-Family Dwellings than under the Reference scenario, and this preference declines over the Planning Period.[107]

Improvements to the energy efficiency of new construction meet the CleanBC Plan targets, and improvements to the energy efficiency of building retrofits reach 10 percent by 2030.[108] PNG does not elaborate on how the assumption of 10 percent was established, stating that it has developed the alternative scenarios to present a range of demand forecasts that could plausibly be expected, depending on how public policies, particularly the CleanBC Plan, are enacted into regulation and law.[109]

With respect to large customer demand, the annual deliveries to Skeena BioEnergy Ltd. are assumed to remain the same as those forecast in the Reference Scenario.[110] Over the longer term, AltaGas Ltd.'s RIPET may offset some of its demand for natural gas with ethane produced from its fractionation plant. Under this situation, PNG states that the demand from RIPET may be reduced to the minimum demand of 410 GJ per day specified in the 15-year firm gas sales agreement entered into with PNG.[111] Accordingly, PNG has used a forecast based on the minimum contract demand, equivalent to approximately 150 TJ per year.[112]

The Competitive Electric scenario assumes a loss of the entire compressor fuel gas load by 2030 for the Fort St. John Service Area.[113] In the Tumbler Ridge service area, PNG assumes that the CNRL demand will reduce to 550 TJ per year, compared to 586 TJ per year under the Reference scenario.[114]

[101] Exhibit B-1, Section 7.4.1, p. 112.
[102] Exhibit B-3, BCUC IR 30.1.
[103] Exhibit B-1, Section 7.3.3.2, p. 101.
[104] Exhibit B-1, Section 7.3.3.2, pp. 101-102.
[105] Exhibit B-1, Section 7.4.1, p. 112.
[106] Exhibit B-1, Section 7.4.2, p. 112.
[107] Exhibit B-1, Section 7.4.2, pp. 112-113.
[108] Exhibit B-1, Section 7.4.2, p. 113.
[109] Exhibit B-3, BCUC IR 31.1.
[110] Exhibit B-1, Section 7.3.3.2, p. 101.
[111] Exhibit B-1, Section 7.3.3.2, pp. 100-101.
[112] Exhibit B-1, Section 7.3.3.2, p. 101.
[113] Exhibit B-1, Section 7.3.3.2, p. 101.
[114] Exhibit B-1, Section 7.3.3.2, p. 104.

PNG compares the forecast gross annual demand scenarios for the Planning Period for all service areas in Figures 59 to 62 as shown below.[115]

Figure 59: Forecast Total Annual Demand PNG-West (All Scenarios)

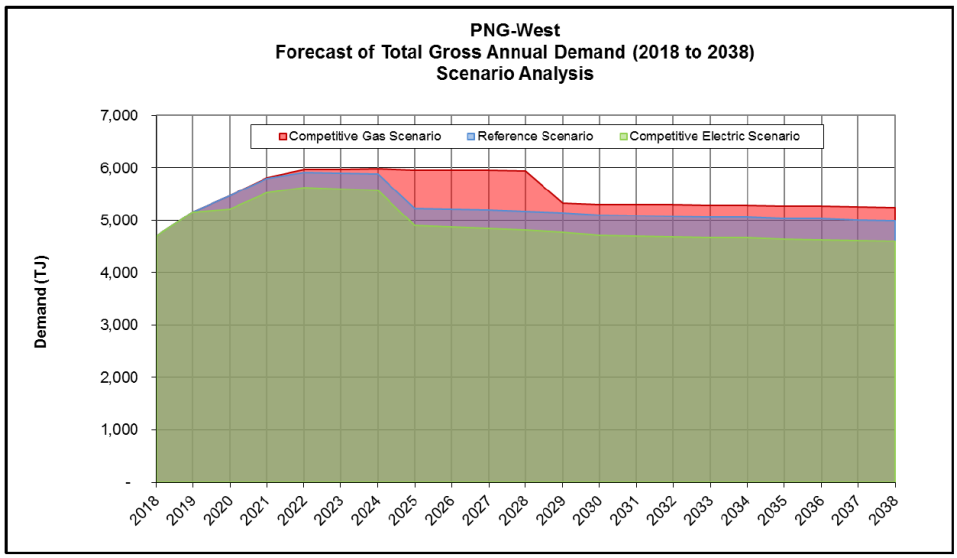
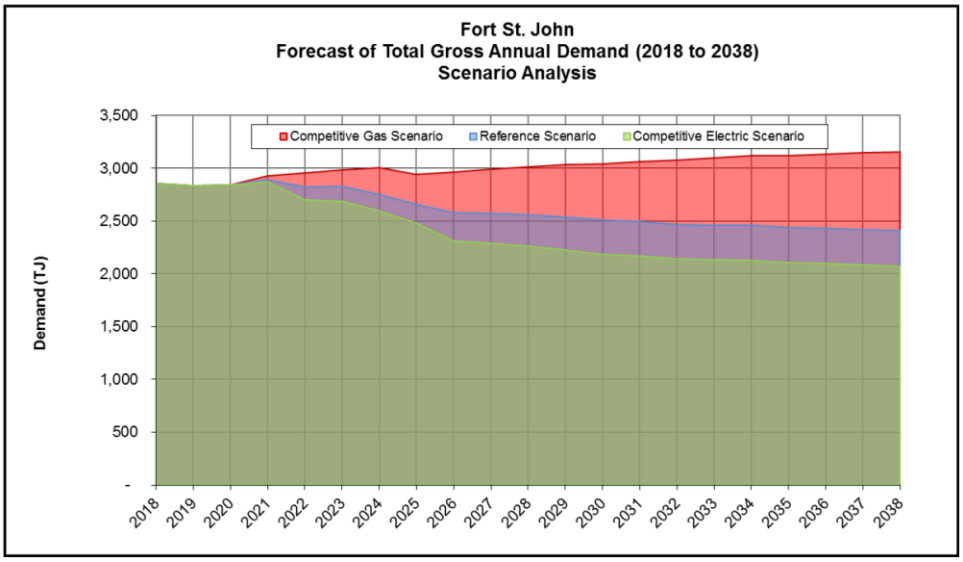


Figure 60: Forecast Total Annual Demand Fort St. John (All Scenarios)



[115] Exhibit B-1, Section 7.4, pp. 118-121.

Figure 61: Forecast Total Annual Demand Dawson Creek (All Scenarios)

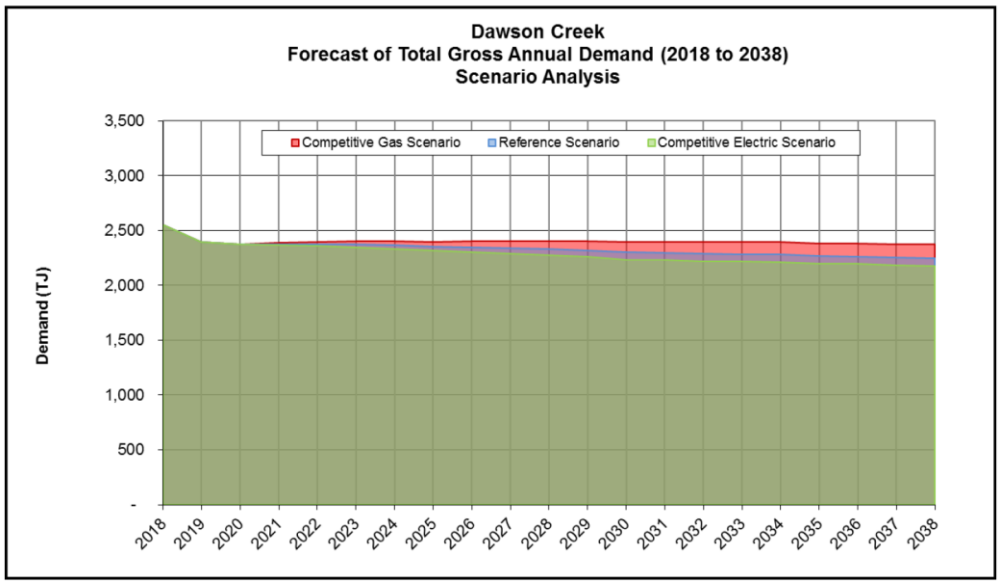
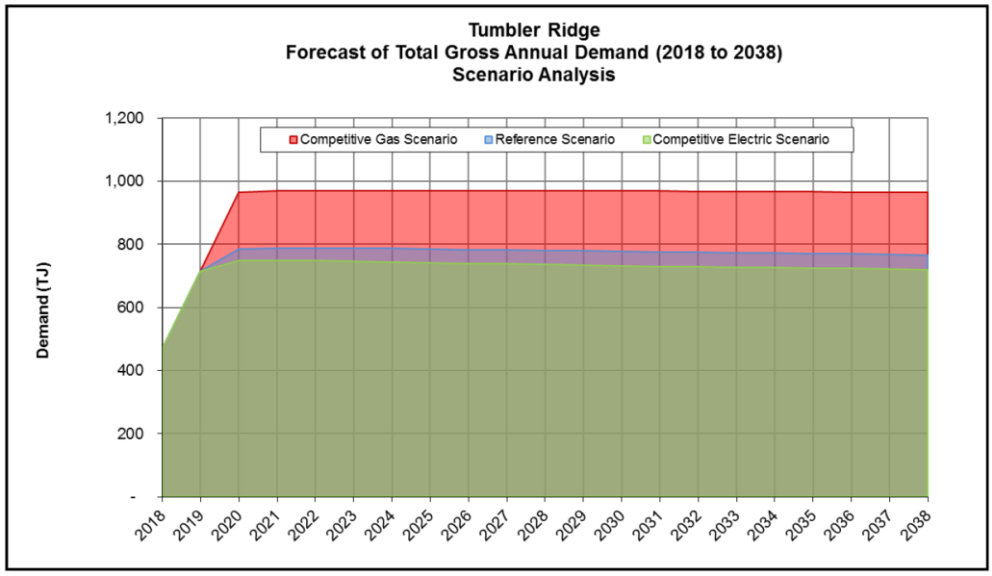


Figure 62: Forecast Total Annual Demand Tumbler Ridge (All Scenarios)



Panel Determination

The Panel notes that all three of PNG's demand scenarios show a flattening of demand at approximately the 2020 level with variations that remain within a relatively tight range. As scenarios are included to enable the utility to assess resilience and plan for change beyond "business as usual," the Panel would have expected to see more variation between the three scenarios based on different underlying assumptions. The Panel finds that the forecast models set out in PNG's 2019 CRP are sufficient to satisfy Order G-155-15 for planning purposes, and is satisfied that PNG has included an appropriate sensitivity analysis, despite not including the gain or loss of a large commercial or industrial customer demand as directed in Order G-140-14. However, the Panel considers it useful for PNG to consider scenarios that will more dramatically impact future demand, whether positively or negatively, in the region. Accordingly, **the Panel directs PNG to include more extreme planning scenarios, including the gain or loss of a large commercial or industrial customer demand as directed in Order G-140-14 in its next long-term resource plan**.

RECAP and the Demand Forecast

Subsequent to the filing of this Application, the BCUC approved PNG's application for its Process for Allocation of Reactivated Capacity (RECAP) and of a Large Volume Industrial Transportation Rate (RS 80).[116] The RECAP process is an open season for PNG to assess the existing and prospective demand for gas transportation capacity available on PNG-West's transmission system and to allocate its existing and prospective available capacity of approximately 80 Million Standard Cubic feet per day (MMSCFD). However, PNG submits that this capacity is not included in the load forecast or any of its forecasting scenarios as PNG considers the potential demand to be speculative and PNG "will not speculate on any likely uptake of spare capacity".[117]

PNG states that since the RECAP process is entirely dependent on the global demand for LNG and political relationships with Asia, it cannot predict the outcome of this RECAP process. This is evidenced in part during the first quarter of 2019 when PNG held a binding open season for reactivated capacity as well as expansion capacity on its PNG-West transmission system. That open season resulted in parties agreeing to commit up to a total of 326 MMCF/day, which was not sufficient to support the development of the expansion project[118]. PNG further observes that:

> While PNG could reasonably include sufficient additional demand under the Competitive Gas scenario that would result in a fully utilized transmission system, such a forecast provides little if any meaningful information. [119]

PNG submits that the PNG-West transmission system will have sufficient capacity to serve all of the demand from all of the loads that have been identified in the RECAP, and that any resulting capital expenditures, currently estimated at $120 million, will be fully reviewed in subsequent Certificate of Public Convenience and Necessity (CPCN) applications and Revenue Requirement Applications (RRAs).[120]

Positions of the parties

BCSEA submits that the BCUC's established processes would address potential impacts on existing and future ratepayers from the reactivation of one or more compressor stations as a result of subscriptions under the RECAP open season. It states that "[n]evertheless, if there is a substantial throughput then, in BCSEA's view, consideration should be given to advancing the development of the next long-term resource plan."[121] BCSEA therefore regards PNG's exclusion of the RECAP process from the demand forecast to be one of the weaknesses of the 2019 CRP, albeit not a fatal one to acceptance.[122]

BCOAPO takes no position on the issue of RECAP and its exclusion from PNG's demand forecast.

PNG Reply Submission

In reply to BCSEA, PNG reiterates that any projects to reactivate existing and under-utilized capacity on the PNG-West transmission system will be subject to BCUC review through a CPCN application, a section 44.2 UCA expenditure schedule or an RRA. Parties will then be able to assess the implications of these projects, specifically, the ability of the PNG-West transmission system to serve current and future loads, and impacts on existing and future customers.[123] PNG further submits that "PNG has determined the available spare capacity on its PNG-West system available to an open season giving due consideration of the current and future demand from its existing customers." PNG is confident that "[u]nder any outcome of the RECAP open season, the PNG-

[116] Decision and Order G-35-20.
[117] Exhibit B-1, pp. 108 and 123.
[118] Exhibit B-3, BCUC IR 24.1.
[119] Exhibit B-1, p. 106.
[120] Exhibit B-1, p. 106.
[121] BCSEA Final Argument, para.71, p. 18.
[122] Ibid., para 77, p. 19.
[123] PNG Reply Argument, para. 15, p. 4.

West system will have sufficient capacity to serve all the demand from all the firm loads that have been identified in the 2019 Consolidated Resource Plan."[124]

Panel Determination

The Panel finds that the exclusion of RECAP volumes from PNG's demand forecast is reasonable. The Panel agrees with PNG that the nature of the RECAP open season process makes it inappropriate to include specific outcomes in PNG's demand forecast in the 2019 CRP. The Panel further agrees that actual impacts of reactivating, as a result of RECAP, existing and under-utilized capacity on the PNG-West system's ability to serve current and future loads and impacts on customers are best addressed in the context of future applications for approval of CPCNs, section 44.2 UCA expenditure schedules or RRAs.

2.3.1.2 Peak Demand

By Order G-155-15, the BCUC directed PNG to include an aggregate peak day demand forecast of the system in future resource plans.

PNG submits that the primary purpose of the peak demand forecast is to provide a forecast of the delivery capacity required during extreme cold weather, in order to allow PNG to plan for any physical expansions to its existing pipeline capacity. This is also known as the "design day" demand.[125]

PNG states that the design day demand is the maximum demand that the system is expected to serve. It is determined based on a "perfect storm" of maximum firm industrial demand and temperature sensitive space heating demand from the residential and commercial market segments during the coldest day or peak demand day that can be expected.[126] PNG explains that estimates of the peak demand are important for capacity and gas supply planning purposes.[127]

PNG states that it estimates the design day demand using the same method developed for determining peak day gas supply requirements for the purposes of developing its annual firm gas supply contracting strategy.[128] The design day demand for each of PNG's customer segments is determined based on a mathematical relationship between ambient air temperature and gas consumption that has been determined empirically from historical weather and billed consumption data.[129]

The design day demand of residential customers was calculated using the residential end-use model multiplied by the number of customers forecast.[130] In the case of small and large commercial and small industrial customers, their portion of the peak day demand is determined from analysis of their historical billing and weather data.[131]

PNG's design day demand forecast under the Reference, Competitive Gas and Competitive Electric scenarios is shown in Table 1 below, which demonstrates that under all scenarios the system capacity exceeds the design day demand.[132]

[124] PNG Reply Argument, para. 15, p. 4.

[125] Exhibit B-1, Section 7.1, p. 77.
[126] Exhibit B-1, Section 7.5, p. 121.
[127] Exhibit B-1, Section 7.5, p. 121.
[128] Exhibit B-1, Section 7.5, p. 121.
[129] Exhibit B-1, Section 7.5, p. 121.
[130] Exhibit B-1, Section 7.5, p. 121.
[131] Exhibit B-1, Section 7.5, p. 121.
[132] Exhibit B-3, BCUC IR 34.2.

Table 1: Forecast Design Day Demand

	Design Day Demand in 2038 vs. Current System Capacity (GJ/D)			
	Reference	Competitive Gas	Competitive Electricity	System Capacity
PNG-West at Summit Lake	39,889	42,813	37,558	68,000/134,309*
Fort St. John	25,306	31,846	22,740	na**
Dawson Creek MS52	16,103	17,514	15,330	27,597
Tumbler Ridge Plant	3,243	3,941	3,049	5,731

* Showing both currently available and reactivated capacity
** The Fort St. John system is a distribution network supplied from nine receipt points

2.3.1.3 Overall Findings on PNG's 2019 CRP Gross and Peak demand forecasts

PNG submits that it has maintained, and in some cases increased, the level of rigour employed in the PNG-West 2014 Resource Plan and PNG(N.E.)'s 2015 Resource Plan in developing demand forecasts for all its customer classes, including large customers. The BCUC had accepted both the PNG-West 2014 Resource Plan[133] and PNG(N.E.) 2015 Resource Plan[134] as adequate under section 44.1(2) of the UCA.[135]

In particular, PNG points out:[136]

> In its Decision approving the 2014 Resource Plan for PNG-West, the BCUC accepted PNG's forecasting method stating that it "is more transparent than the one previously used and produces a reasonable forecast". The BCUC went one step further, noting the "improvements PNG has made to its forecasting methodology and appreciates that PNG clearly identified the assumptions and inputs that went into its forecast. Further, the Panel also notes that the methodology was practical, frugal in its implementation and not overly elaborate. The Panel commends PNG for this approach.

Positions of the parties

BCSEA acknowledges that PNG's 2019 CRP complies with section 44.1(2)(a) of the UCA by providing a gross demand forecast for the Planning Period. BCSEA further accepts PNG's explanation as to why the 2019 CRP does not provide any consolidated results in the demand forecast section.

BCOAPO states that "in general terms, it has no issue with PNG's method of forecasting the demand as adopted in the Application."[137]

Panel Determination

Pursuant to section 44.1(2)(a) of the UCA, the Panel must satisfy itself that PNG's 2019 CRP includes an estimate of demand for energy that the utility must serve during the Planning Period in the absence of demand side management measures.

While section 44.1(2)(a) of the UCA does not specify the particular methodology that a utility must use in developing its demand forecast and all forecasts are inherently uncertain, the Panel must nonetheless

[133] Order G-140-14.
[134] Order G-155-15.
[135] PNG Final Argument, para. 10, p. 3.
[136] PNG Final Argument, para. 5, p. 2.
[137] BCOAPO Final Argument, p. 4.

determine whether PNG has provided sufficient information about the underlying assumptions to satisfy the Panel that the total demand estimate provided in this Application is sound and ought to be accepted.

As evident in the above summary of PNG's approach to developing its demand forecasts, PNG has not completed a REUS since 2013 to support its assumptions with respect to its residential demand forecast. While the Panel has concerns with the validity of some of these assumptions, given the results are seven years old, the Panel notes PNG has nonetheless developed its residential demand based on the results of its 2013 REUS and 2019 Customer Attitudes Survey. In addition, PNG has continued, and in some cases increased, the level of rigour employed in previous resource plans in developing its demand forecasts. Given this, the Panel accepts PNG's residential demand forecast methodology is reasonable and is satisfied with PNG's residential demand forecast.

While PNG has used the results of the 2013 REUS and the 2019 Customer Attitudes Survey to forecast residential and small commercial demand, the Panel notes PNG's empirical "bottom up" methodology used to develop its industrial demand forecast. The Panel is satisfied that this methodology is appropriate and accepts PNG's industrial customer demand forecast as presented in the 2019 CRP.

PNG has based its gross demand forecast on historical demand, population growth, construction trends, and increased efforts at energy efficiency. The Panel notes that, apart from Dawson Creek, the variance between the 2018 residential use per account as forecast in the PNG-West 2014 Resource Plan and the PNG(N.E.) 2015 Resource Plan, compared to actual 2018 residential use per account, is not insignificant.[138] While the Panel is concerned that the demand forecast for Tumbler Ridge in particular may be overestimated, given that the overall demand for Tumbler Ridge is much lower than that for PNG's other service areas, the impact on gross demand likely falls within an acceptable range.

Despite the shortfalls identified above, the Panel notes that PNG(N.E.) has improved the rigor of its sensitivity analysis in compliance with the BCUC's directions in Order G-60-13[139] and Order G-155-15, and has also addressed the additional directives in Order G-155-15 to improve the demand forecasts in this resource plan. The Panel therefore accepts the overall gross demand forecast as presented.

As noted above, in 2015 the BCUC ordered PNG to include aggregate peak day demand forecast of the system in future resource plans, stating that this was considered helpful when determining gas supply requirements to meet the aggregated peak day demand.[140] **The Panel finds that PNG has satisfied the directive in Order G-155-15 by including an aggregate peak day demand forecast for the PNG system in this Application.**

While the Panel does have concerns about specific aspects of the current demand forecast, as outlined above, the Panel is generally satisfied that the demand estimate provided is reasonable based on the BCUC's endorsement of PNG's demand forecasting methodology in previous decisions, and the Panel views that methodology remains valid for the 2019 CRP. Taking this into consideration, the **Panel finds that PNG's estimate of demand before new demand-side measures satisfies the requirements of section 44.1(2)(a) of the UCA.**

2.3.2 Estimate of demand after taking demand-side measures

In a long-term resource plan, a utility must provide a plan of the demand that can be avoided through demand-side measures in order to satisfy the following filing requirements set out in sections 44.1(2)(b), (c) and (f) of the UCA:

[138] Exhibit B-3, BCUC IR 25.1.
[139] BCUC Order G-60-13.
[140] Order G- 155-15.

(2) Subject to subsection (2.1), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(b)a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c)an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

…

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

To promote regulatory efficiency of future resource plan filings, the BCUC has previously directed PNG to file the following information in the DSM portion of its next and subsequent long-term resource plans[141]:

a. Different DSM funding scenarios which should at a minimum include a "reference" DSM funding scenario with "high DSM" and "low DSM" scenarios relative to the reference funding scenario;

b. An estimate of the demand for energy that the public utility expects to serve after it has taken all reasonable cost-effective demand-side measures. Given the BC energy objective to "take demand side measures and to conserve energy," the [BCUC] expects that PNG should be able to identify sufficient cost-effective DSM to result in a load forecast adjustment for DSM that exceeds "the precision of the forecast";

c. An analysis of each DSM funding scenario, including average bill and rate impacts for each customer class; and

d. An analysis that shows how PNG has taken into account regional differences (such as different customer composition and customer preferences) in both identifying DSM opportunities and the extent to which DSM programs will be taken up in the different regions.

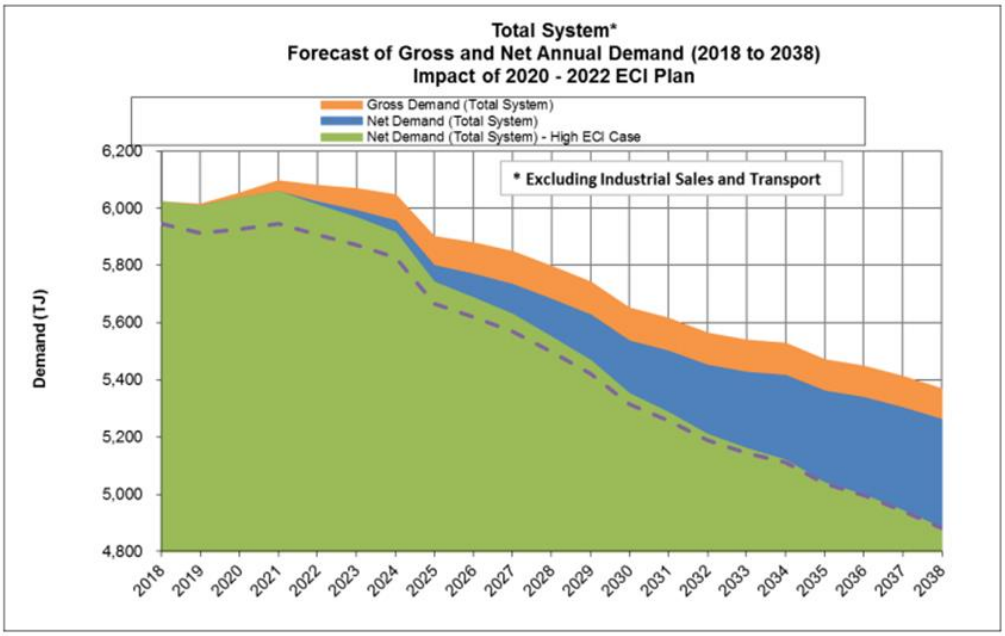
In its Application, PNG is concurrently seeking approval of its 2019 CRP, which includes a forecast of DSM for the purposes of section 44.1 of the UCA, and an expenditure schedule for its ECI portfolio under section 44.2 of the UCA, which is addressed in section 3 of this decision. Underpinning PNG's DSM forecast and expenditure schedule is the DSM Plan, included as Appendix F in the Application. The DSM Plan covers the period 2020 to 2022 and contains a detailed breakdown of expenditures within PNG's ECI portfolio across different DSM programs, and the forecasted energy savings resulting from adoption of these programs. For the purposes of forecasting net demand, that is, demand after DSM, in the 2019 CRP, PNG assumes a continuation of a similar level of funding as in the ECI portfolio in 2023 and beyond, with market saturation occurring after five years (2027); the resultant demand reduction is the "reference DSM funding scenario."[142]

In addition to the reference DSM funding scenario, PNG has developed a "high DSM" scenario based on the results of the 2017 Conservation Potential Review (CPR) Market Potential Review that estimated a cumulative gas saving by volume of three percent from 2016 to 2022, increasing by 0.5 percent annually and reaching 7.9 percent by 2035.[143] PNG has not included an analysis of a "low DSM" funding scenario, which it submits would correspond to a DSM portfolio that meets the adequacy requirements of the DSM Regulation only.[144] This is further discussed in subsection 2.5.2 of this decision. The demand savings resulting from the reference and high

[141] Order G-155-15; Decision PNG (N.E.) Ltd 2015 Resource Plan for the Fort St. John, Dawson Creek and Tumbler Ridge Distribution Systems, p. 10.
[142] Exhibit B-1, p. 130.
[143] Exhibit B-1, p. 130.
[144] Exhibit B-1, p. 21.

DSM scenarios are applied to the gross demand forecast and illustrated in Figure 64 (reproduced below), Figure 65 and Table 39 in the Application.[145]

Figure 64: Forecast Gross and Net Annual Demand (TJ)



With respect to BCUC directive c. referenced above, PNG estimates that the bill impact of its ECI portfolio on its residential customers would be approximately $8 per year.[146] PNG estimates the cost of the "high DSM" scenario based on program expenditures that are 2.5 percent of PNG's gross margin, which is approximately double the level of ECI expenditures proposed.[147] Using these assumptions, PNG estimates an average annual expenditure in the short term of between $39 and $45 per customer (including commercial, residential and industrial customers).

PNG further estimates the impact of ECI expenditures related to a "high DSM" scenario, amounting to $5 million over the period 2020 through 2022, to be as follows:[148]

All customers in:	Impact ($/GJ)	Residential UPA (GJ)	Bill Impact ($)
PNG-West	$0.20	67.0	$14
Fort St. John/Dawson Creek	$0.17	104.4	$18
Tumbler Ridge	$0.15	72.8	$11

With respect to BCUC directive d. referenced above, PNG explains that its 2019 Customer Attitudes Survey was targeted at both residential and commercial customers and addressed a range of topics, including attitudes and beliefs about the environment and participation and interest in energy-efficiency initiatives.[149] Section 6 of the Application discusses customer demand, including penetration rates by end use in each of the PNG(N.E.), PNG-West (East) and PNG-West (West) regions.

[145] Exhibit B-1, p. 132.
[146] Exhibit B-1, p. 130.
[147] Exhibit B-7, BCUC IR 1.63.1.
[148] Exhibit B-7, BCUC IR 63.2.
[149] Exhibit B-1, pp. 59-62.

With respect to addressing section 44.1(2)(f) of the UCA, PNG explains that it is able to fulfil its capacity and energy requirements without the need for additional DSM:

> PNG has not identified any facilities that it intends to construct to serve the demand from current and existing customers. As illustrated by Table 35, p. 122 of the Application, PNG anticipates having adequate capacity to meet the forecast design day demand under all planning scenarios. Every year, PNG prepares an Annual Gas Contracting Plan (ACP) that describes the physical gas supply resources PNG intends to secure to meet the projected peak day and average daily gas demand of PNG's gas sales customers over the gas year beginning November 1. Each ACP is subject to review and acceptance by the BCUC. The physical gas supply resources that PNG contracts for each year reflects the forecast design day demand expected in the coming winter. This demand is based on projected customer counts and UPA's that have been updated based on the most recent counts and UPA's which reflect the impact of PNG's ECI (DSM) programs.[150]

Positions of the parties

BCSEA accepts that a forecast of gross and net (after DSM) total system demand for 2018 to 2038 is provided in the Application, as required by section 44.1(2)(c) of the UCA.[151]

BCSEA submits that one result of conflating the long-term DSM Plan and the DSM expenditure schedule is that the DSM Plan does not address any years beyond the period (2020 to 2022) covered by the expenditure schedule. However, BCSEA does not consider this to be a practical problem in the current circumstances, because the practical challenge is for PNG to fully implement the proposed 2020-2022 ECI expenditure schedule rather than underspending as has occurred in the past.[152]

PNG Reply Submission

In its reply, PNG submits that its decision to limit its DSM Plan to the three years spanned by its expenditure schedule is a pragmatic one that reflects the continued evolution of the ECI portfolio. The performance of PNG's existing and proposed ECI portfolio through 2022 will inform its further expansion over the following three to five years.[153]

Panel Determination

PNG has historically faced challenges in addressing DSM in its long-term resource plan and the BCUC has previously provided direction to PNG on how to meet the requirements of section 44.1(2) of the UCA.

The Panel notes that PNG's DSM Plan and ECI portfolio span only three years. The Panel is of the view that the pragmatic approach adopted by PNG does not appear to have been contemplated in previous BCUC directives. However, the **Panel accepts that PNG has identified acceptable demand-side measures as required by UCA section 44.1(2)(b) of the UCA, and in accordance with UCA section 44.1(2)(c), has provided an estimate of demand after such measures are implemented**.

PNG has presented different funding scenarios and undertaken an analysis of average bill and rate impacts in relation to residential accounts and penetration of programs on a regional basis. However, PNG has failed to analyze the bill impact on other customer groups as previously directed by the BCUC, and the Panel finds that PNG has only partially fulfilled the directives in Order G-155-15. **The Panel considers the missing information from Order G-155-15 is still relevant, and therefore directs PNG to include an analysis of bill and rate impacts relating to all customer groups in future DSM/ECI Plans.**

[150] Exhibit B-3, Response to BCUC IR 36.6.
[151] BCSEA Final Argument, p. 17.
[152] BCSEA Final Argument, p. 4.
[153] PNG Final Argument, p. 4.

Notwithstanding, the Panel accepts that PNG's 2019 CRP includes a DSM Plan and is satisfied that PNG has provided sufficient details relating to the following requirements of the UCA:

- An estimate of the demand for energy that PNG expects to serve after it has taken cost-effective demand-side measures, at least in relation to residential customers in each region, as required by sections 44.1(2)(b) and (c) of the UCA;

- An explanation of why the demand for energy to be served by new facilities and energy purchases is not planned to be replaced by demand-side measures as required by section 44.1(2)(f) of the UCA, namely, that existing facilities are sufficient to serve anticipated demand; and

- The necessary context for the Panel's overall findings on whether the 2019 CRP meets the requirements in section 44.1(2) of the UCA as set out in section 2.4 of this decision.

Therefore, **the Panel determines that PNG's 2019 CRP has met the filing requirements of section 44.1(2)(b), (c) and (f) of the UCA.**

2.3.3 Facilities

PNG states that the capacity of its transmission and distribution system is sufficient to meet the design day demand of its customers over the entire Planning Period under the Reference, Competitive Gas and Competitive Electric scenarios, as shown in Figures 59 to 62 and discussed in subsection 2.3.1.1 of this decision. PNG further states:

> Leaving aside the prospect of significant additional demand on the PNG-West system as a result of the RECAP, no new supply or capacity resources are required to meet identifiable customer demand at this time or within the near future. The development of resource portfolios was therefore not considered necessary and PNG concludes that there is no requirement to complete a resource portfolio evaluation for this Consolidated Resource Plan.[154]

PNG expects a modest increase in customer additions in its PNG-West service area due to economic activity associated with the LNG Canada project in the Kitimat/Terrace area, which could lead to an increase in new services over the next three to five years. PNG states "if other major LNG export projects proceed, this could increase the additions of new services and mains beyond 2024."[155]

By Order G-155-15, to address constraints to potential new demand in the Dawson Creek system, the BCUC directed PNG to confirm whether it has been able to safely remove the self-imposed operating pressure limit on the Sunrise lateral in its next resource plan.

PNG submits it has determined that there is sufficient capacity to reliably serve the customers of Dawson Creek at this time. Further, PNG explains that it "intends to remove this self-imposed limit when and if it establishes the structural integrity of the pipeline through a corrosion survey and investigative digs."[156]

PNG further states it is undertaking activities to assess the integrity of the PNG-West and Tumbler Ridge transmission systems over the next five years and explains its asset integrity plans are driven primarily by its asset risk management process and regulatory compliance requirements:

[154] Exhibit B-1, p. 134.
[155] Exhibit B-1, p. 134.
[156] Exhibit B-1, p. 21.

The activities within this plan are required by CSA Z662-19, are regulatory requirements of the BC Oil and Gas Commission (BCOGC), are well aligned with industry best practice, and are recognized as the established standard for pipeline risk management. As a result, given the specific intended purpose and objective of each of the activities identified in the preamble, no alternatives were considered.[157]

Panel Determination

Section 44.1(2)(d) requires PNG to include a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand, after having taken demand-side measures. The Panel notes that expenditures related to facilities are directed at integrity management, necessitated by both regulation and risk management. The Panel accepts that PNG's demand is unlikely to increase significantly, and accepts that the existing facilities will be adequate to serve forecast demand within the Planning Period, after having taken demand-side measures. **The Panel determines that PNG has satisfied the requirements of section 44.1(2)(d) of the UCA.**

2.3.4 Energy Purchases

Section 44.1(2)(e) of the UCA requires that the resource plan include information regarding the energy purchases from other persons that PNG intends to make in order to serve the demand for energy that it expects to serve after it has taken cost-effective demand-side measures.

PNG has engaged a third-party to provide energy management services (EMS) in order to facilitate natural gas supply and transportation contracts necessary to meet the supply requirements for its geographically dispersed customer base.[158] The EMS provider is responsible for: gas supply planning and resource selection analysis; gas supply contract negotiation and administration; daily energy management services; and monitoring and reporting on credit, hedging positions and gas prices.[159]

PNG explains that the foundation for management of its gas supply portfolio is the ACP process, which is subject to review and acceptance by the BCUC prior to its implementation.[160] The ACP describes the physical gas supply resources PNG intends to secure to meet the forecast average daily gas and peak day demand of its customers over the gas year beginning each November 1.[161]

On July 26, 2019, the BCUC accepted PNG's 2019/2020 ACP as being in the public interest.[162]

PNG states it has developed a supply resource portfolio of gas commodity, storage and pipeline contracts in order to satisfy its gas contracting objectives. PNG ensures a secure reliable supply by entering a diversified gas supply portfolio to minimize the risk associated with any one particular supply option.[163] PNG's gas supply portfolio includes daily, monthly, seasonal and peaking gas supply contracts as well as gas storage services.[164] The storage services are stated to reduce the utility's exposure to the spot market and provide security of supply and operational flexibility to manage load fluctuations due to weather, effectively providing additional gas cost certainty and winter price diversity.[165]

[157] Exhibit B-7, BCUC IR 67.0.
[158] Exhibit B-1, Section 9.5, p. 135.
[159] Exhibit B-1, Section 9.5, p. 135.
[160] Exhibit B-1, Section 9.5.1, p. 136.
[161] Exhibit B-3, BCUC IR 38.1.
[162] Letter L-39-19, dated July 26, 2019.
[163] Exhibit B-1, Section 9.5.1, p. 136.
[164] Exhibit B-1, Section 9.5.1, p. 136.
[165] Exhibit B-1, Section 9.5.1, p. 136.

Over the medium term, PNG does not anticipate any significant changes to its mix of supply resources.[166] Over the long term, however, PNG states that there may be a possibility to secure supply shipped through Coastal Gas Link,[167] once completed, to provide additional supply security and potential price diversification. Similarly, if more interconnectivity with the AECO market is developed, PNG explains that it could look to source gas from that market. However, at this time, PNG states that both alternatives are purely speculative.[168]

PNG submits that the biggest risk it has identified with respect to its committed or potential supply resources is a supply disruption from a pipeline event, such as the Westcoast T-South rupture which occurred in October 2018.[169] PNG states that it is investigating the feasibility of constructing a LNG storage facility in Prince Rupert, which could provide supply during winter peak demand as well as emergency supply in the event of an outage on the Westcoast T-South or PNG-West transmission systems.[170] PNG has also been in discussions with Coastal Gas Link regarding a possible emergency interconnection at some point along its line, as well as exploring the provision of LNG from small LNG facilities that could be located in PNG's service areas.[171]

Positions of the Parties

Interveners did not comment on PNG's energy purchases.

Panel Determination

In its decision on PNG's 2014 Resource Plan and DSM Application, the BCUC directed PNG to include an update on all gas supply options and to examine the merits of these options.[172] This directive followed an observation by the Panel that "there appear to be a number of additional gas supply options on the horizon which may be beneficial to customers."[173] PNG did not address this in its 2015 Resource Plan, nor has it addressed it here. **The Panel finds that PNG has not fulfilled this directive in Order G-140-14 and directs PNG to file an update on all gas supply options and an examination of the merits of these options by December 31, 2022.**

The Panel determines that PNG has satisfied the requirements of section 44.1(2)(e) of the UCA. The Panel acknowledges that given PNG's demand is not expected to grow, sufficiency of supply is not likely to be a problem. The risk to supply that PNG has identified relates to potential pipeline rupture, and the Panel is satisfied that PNG is exploring options for address interruptions related to pipeline integrity. However, the Panel notes that while PNG is considering ways to secure the supply for Westcoast T-South and PNG-West from potential disruption due to pipeline integrity by constructing a new storage facility in Prince Rupert, it is unclear what options are being considered for PNG(N.E.). **Accordingly, the Panel directs PNG in its next long-term resource plan to provide further analysis of its resiliency plan, including supply risks and its back-up plan in the event of a pipeline rupture, loss of supplier, or similar disruption, for the PNG-West and PNG(N.E.) systems.**

2.3.5 Other Information Required by the BCUC

2.3.5.1 Resource Plan Weightings

In its decision for the PNG(N.E.) 2015 Resource Plan, the BCUC directed PNG(N.E.) to continue to identify and weight objectives in subsequent resource plans, irrespective of whether or not the resource plan puts forward

[166] Exhibit B-7, BCUC IR 65.2.
[167] Exhibit B-1, p.51 The Coastal Gas Link Pipeline Project is a 650km natural gas pipeline from the Dawson Creek Area to the proposed Shell LNG facility in Kitimat.
[168] Exhibit B-7, BCUC IR 65.2.
[169] Exhibit B-7, BCUC IR 65.3.
[170] Exhibit B-7, BCUC IR 65.5.
[171] Exhibit B-7, BCUC IR 65.5.
[172] Order G-140-14.
[173] APPENDIX A to Order G-140-14, PNG-West 2014 Resource Plan and PNG (N.E.) DSM Resubmission, p 12.

any new projects/initiatives. PNG(N.E.) was further directed to treat those values as actuals (as opposed to hypotheticals) for purposes of evaluation of resource options.[174]

Further, the BCUC determined that the objectives and weights should typically be held consistent from one resource plan to the next, save for if and when PNG(N.E.) can substantiate the need and reasons for any changes thereto.[175]

In its 2019 CRP, PNG states it has maintained the planning objectives and benchmarks presented in the PNG-West 2014[176] and PNG(N.E.) 2015 Resource Plans[177]. PNG explains that in accordance with the directive in Order G-155-15, it will consistently apply the weightings identified in its resource planning objectives when evaluating alternatives to resource portfolios, projects or other initiatives.[178]

PNG states it has reviewed the weightings assigned to each of the planning objectives and amended them to reflect a greater consideration of Objective 6 - Alignment with the B.C. Government's Energy Objectives.[179] PNG explains that the greater weighting is appropriate in light of an increased focus on energy conservation and renewable natural gas resulting from the Government's CleanBC Plan.[180]

Table 1 summarizes PNG's six resource planning objectives and identifies the changes to the weightings in the 2019 CRP.[181]

Table 1: Changes to weightings applied to resource planning objectives

RESOURCE PLANNING OBJECTIVES			
Objective		Weights	
		PNG(N.E.) 2015 Resource Plan	PNG Consolidated 2019 Resource Plan
1	Safe, reliable service	30%	30%
2	Least cost service	**30%**	**25%**
3	Economic viability of the utility	10%	10%
4	Stable Rates	10%	10%
5	Environmental and socio-economic impacts	10%	10%
6	Alignment with the B.C. Government's Energy Objectives	**10%**	**15%**
		100%	100%

PNG states that the CleanBC Plan target of 15 percent renewable content in natural gas delivered to residential and industrial customers by 2030 is expected to have the most direct impact on PNG.[182] PNG submits that the costs of complying with the CleanBC Plan 15 percent renewable target, the Methane Regulations currently in effect, or any future regulations enacted to support the B.C. Government's energy objectives, should not be borne by its shareholder, or that "PNG should attempt to reduce its cost of maintaining and operating its pipeline systems."[183]

[174] PNG(N.E.) 2015 Resource Plan, pp.3-4.
[175] PNG(N.E.) 2015 Resource Plan, p. 4.
[176] PNG-West 2014 Resource Plan.
[177] Exhibit B-1, Section 1.4, p. 9.
[178] Exhibit B-1, Section 1.4, p. 10.
[179] Exhibit B-1, Section 1.4, p. 10.
[180] https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf.
[181] Exhibit B-1, Section 1.4, p. 11.
[182] Exhibit B-3, BCUC IR 1.1.
[183] Exhibit B-3, BCUC IR 1.1.

Consequently, PNG submits that while British Columbia's increased focus on reducing GHG emissions warranted an increased focus by PNG, in terms of an increased weighting on its Resource Planning Objective, PNG was not prepared to reduce its focus on providing safe and reliable service (Objective 1), nor on the environmental and socio-economic impacts of its operations (Objective 5). PNG submits maintaining predictable rates for its customers (Objective 4), and ensuring the economic viability of PNG through a fair and adequate return for its shareholder (Objective 3) are in the best interests of its customers, and the prosperity of the northern communities where PNG's employees live and work.[184]

PNG submits that the CleanBC Plan, and regulations leading to the reduction of GHG emissions, warrant an increased focus and PNG expects that additional costs will be associated with attaining these emission reduction targets. While PNG states that it remains frugal and diligent about the impact of even small cost increases on its customers, PNG expects that the current and future regulatory environment provides ample signals that the objective of reducing GHG emissions must take an increased priority in relation to the objective of reducing costs to its customers.[185]

In light of these considerations, PNG submits that an increase of 5 percent to Objective 6 is sufficient to raise its priority relative to the other objectives, while not significantly diminishing PNG's focus on the provision of least cost service (Objective 2).[186]

Position of the Parties

Interveners did not comment on PNG's adjustments to the weightings of the Resource Planning Objectives.

Panel Discussion

The Panel accepts PNG's change in weightings to the Resource Planning Objectives, but is somewhat concerned with PNG's statement that potential rate impacts of British Columbia's clean energy initiatives should not be borne by its shareholder.[187] The Panel expresses no view as to whether ratepayers or the shareholder should bear the costs of these initiatives. The potential for a specific resource planning objective to impact rates is not a matter that can or should be considered in the abstract.

2.3.5.2 LNG and CNG Strategy

In its decision for the PNG(N.E.) 2015 Resource Plan, the BCUC noted that although PNG(N.E.) stated it was exploring how it might participate in the micro-LNG and Compressed Natural Gas (CNG) markets to provide or supply facilities, PNG(N.E.) provided few specific details of the overall strategy and plans in the 2015 Resource Plan, particularly regarding the benefit or cost to existing ratepayers. The BCUC directed PNG(N.E.), as specified in the Guidelines, to include in future resource plans an action plan consisting of the detailed acquisition steps for those resources which need to be initiated over the next four years to meet the most likely gross demand forecast.[188]

PNG states that it has not pursued its regional LNG and CNG strategy to any significant degree,[189] and explains that in the four years since filing its 2015 Resource Plan, PNG has not proceeded beyond screening level assessments of potential opportunities for providing LNG/CNG to remote communities. PNG submits that the size of the community, along with the lack of significant commercial or industrial load, and the distance from supplies, either of LNG/CNG or fuel gas pipelines, challenge the cost competitiveness of natural gas service

[184] Exhibit B-3, BCUC IR 1.1.
[185] Exhibit B-3, BCUC IR 1.1.
[186] Exhibit B-3, BCUC IR 1.1.
[187] Exhibit B-3, BCUC IR 1.1.
[188] PNG(N.E.) 2015 Resource Plan Decision, p. 21.
[189] Exhibit B-1, p. 22.

compared to existing propane supply. PNG states that it continues to work with communities desiring natural gas service to ascertain current and projected loads.[190]

Panel Determination

The Panel is satisfied that PNG has explored the potential opportunities for providing LNG/CNG to remote communities and that PNG continues to work with those communities that are interested in these options and acknowledges the challenges faced by PNG in developing its LNG/CNG strategy.

Given the challenges identified by PNG, the Panel notes that, at this time, there appear to be limited opportunities for PNG to develop and implement a cost-effective LNG/CNG strategy. Further, there appears to be limited value in pursing an action plan with respect to LNG/CNG acquisition, considering PNG forecasts a reduction in demand forecasts over the Planning Period. **Accordingly, with respect to LNG and CNG, the Panel rescinds the directive at section 9.1 of the PNG (N.E.) 2015 Resource Plan Decision accompanying Order G-155-15 requiring PNG to include in future resource plans an action plan consisting of the detailed acquisition steps for those resources which need to be initiated over the next four years to meet the most likely gross demand forecast.** The Panel does, however, note that these considerations are set out in the Guidelines and reminds PNG that these should be applied, where necessary, to PNG's specific circumstances when developing its future long-term resource plans.

2.3.5.3 Resource Planning Guidelines

In 2003, the BCUC established the Guidelines that set out a process to assist utilities in the development of resource plans under the UCA. PNG provides a summary of the process outlined in the Guidelines[191] and identifies the steps it has undertaken in developing the 2019 CRP consistent with the Guidelines.[192]

PNG identifies a number of aspects of the Guidelines that it "has not followed, in a formal and strict sense" including the following:

(i) the measurement of supply and demand resources;
(ii) the development of multiple resource portfolios;
(iii) the evaluation and selection of resource portfolios; and
(iv) the development of an action plan.[193]

PNG submits that it interprets the Guidelines as providing general guidance rather than prescriptive direction to utilities and that omitting one or more aspects of the Guidelines does not preclude the BCUC from finding that the 2019 CRP meets the requirements of section 44.1(2) of the UCA.

PNG submits that it is not a large utility and has limited resources[194] and has undertaken a resource planning process that "reflects the circumstances and resources of a small natural gas distribution utility" and "it has adhered to the Guidelines where they are relevant and applicable to PNG's operating environment."[195] PNG submits that the Guidelines do not distinguish between utilities that provide generation, transmission or distribution services and that the BCUC should consider the unique operating circumstances when referring to the Guidelines. Further, some aspects may apply more readily to integrated electric utilities and PNG provides the following submission made by FortisBC Energy Utilities (FEU) in its 2014 Resource Plan and the BCUC in its decision:

[190] Exhibit B-1, p. 63.
[191] Exhibit B-1, p. 6.
[192] Ibid, pp.7-9.
[193] Ibid, p. 6.
[194] Exhibit B-3, BCUC IR 39.1.
[195] Ibid, p. 7.

> For a gas utility that does not own its own gas reserves and files for approval of its Annual Contracting Plan and whose bill is disaggregated showing supply side resource (gas) costs separately, the purpose of a Resource Plan is not to develop alternative supply side resource portfolios for comparison to alternative demand side resource portfolios… Rather its purpose is primarily to assess energy delivery infrastructure requirements needed to deliver gas to end-use customers on the natural gas utility system.
>
> The Panel agrees with the FEU that the steps required to undertake a resource plan for an integrated electric utility are different than for a gas utility. For example, for an integrated electric utility, the load forecast is a critical first step and a portfolio-based approach can be used to develop and evaluate different portfolios of 'network infrastructure/generation investment/energy purchases/DSM' to meet the expected load. However, for the FEU, the load forecast is not such a critical first step. Gas is purchased from the market, new gas infrastructure can generally be put in place in less than five years and the addition of one significant customer can quickly overwhelm any refinement in the load forecasting approach for existing customers.[196]

PNG submits that the 2019 CRP, DSM Plan and its ACP provide a sufficiently detailed view of PNG's operations, customers and demand forecast.[197]

PNG states that a shorter-term action plan over a three to five-year planning horizon would be more relevant and applicable to its current situation. However, PNG submits that the "unique operating circumstances of the utility" refers to the amount of research and analysis required for the development of the resource plan. Therefore, without a reduction in expectations on the amount of analysis required to prepare a shorter-term action plan, PNG does not expect a shorter-term action plan to be more cost effective.[198]

Positions of the Parties

BCOAPO states that it "has no issue with PNG's deviation from four aspects of the resource planning process" and that the BCUC should consider the operating circumstances of the utility in applying the Guidelines.[199]

BCSEA submits that Decision and Order G-189-14 support PNG's argument that its 2019 CRP should be accepted although it did not complete a resource portfolio evaluation.[200] BCSEA further submits that, while PNG's ACP is subject to review and acceptance by the BCUC, it cannot be considered a complete resource portfolio. BCSEA points to the failure to include RECAP and the limited time frame for the DSM Plan as weaknesses that are not fatal to acceptance.

Panel Determination

The Panel concurs with the decision in FEU's 2014 Resource Plan and agrees with PNG that the Guidelines are relevant to the consideration of PNG's long term resource plans. The Guidelines state:

> …The Guidelines provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. More specific directions regarding resource plans will be provided to utilities on a utility to utility basis. Further directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution

[196] Exhibit B-3, BCUC IR 39.1 PNG referencing Decision and Order G-189-14.
[197] Exhibit B-3, BCUC IR 39.1.
[198] Exhibit B-7, BCUC IR 66.1.
[199] BCOAPO Final Argument, p. 5.
[200] BCSEA Final Argument, p. 19.

utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service. (Emphasis added).[201]

In other words, the Panel agrees with PNG that the Guidelines are intended to provide guidance to the utility as to the BCUC's expectations in regard to general standards of assessing a resource plan. A particular guideline may have more relevance to a specific type of utility than to another, in which case it is up to the BCUC to assess the long-term resource plan before it against the general resource planning objectives. In this case, it is up to the Panel to assess whether PNG's 2019 CRP has addressed risk mitigation and all prescribed social and environmental impacts in order to deliver a secure and reliable supply of gas to its ratepayers in the most cost-effective manner over the Planning Period. **The Panel finds that PNG's 2019 CRP provides sufficient information for the Panel to assess its long-term resource plan.**

Securing a reliable supply is essential to the operation of the utility, and although PNG's plan has not considered supply beyond five years, **the Panel finds that PNG has provided evidence that it has sufficient supply to meet its forecast demand over the Planning Period.**

While PNG states that a shorter planning horizon would be more relevant, this will not necessarily result in a more efficient process. PNG will still need to employ a certain level of rigor in projecting demand and determining the availability of reliable, cost-effective supply regardless of the length of the planning horizon.

2.4 Overall Findings on Section 44.1(2) UCA Requirements

The Panel accepts PNG's estimate of gross demand and PNG's demand estimate after taking into account demand-side measures. PNG does not consider many of the industrial projects contemplated for the region will become customers, and therefore predicts that these will have no significant impact on its demand forecast. Given PNG's expectation that demand is forecasted to decrease over the Planning Period under each of the Reference, Competitive Gas and Competitive Electric Scenarios, the Panel is satisfied that no new facilities are likely to be needed. With respect to energy purchases, the Panel agrees with Order G-189-14[202] decision with respect to FEU's 2014 Resource Plan, which accepted that a shorter projection for gas purchases may be acceptable, and found in that case a shorter term is justified.[203] **The Panel therefore determines that PNG's 2019 CRP has met the filing requirements as set out in section 44.1(2) of the UCA.**

2.5 Do the Section 44.1(8) UCA considerations support acceptance?

Section 44.1(8) of the UCA sets out certain things that the BCUC must consider in determining whether to accept PNG's 2019 CRP. The Panel must consider:

(a) The applicable of British Columbia's energy objectives;
(c) Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and
(d) The interests of persons in British Columbia who receive or may receive service from the public utility.

The Panel considers each of these requirements in turn, which are addressed in subsections 2.5.1 to 2.5.3. The Panel's overall findings on section 44.1(8) of the UCA considerations are included section 2.6.

[201] BCUC Resource Planning Guidelines, p. 2.
[202] BCUC, FortisBC Energy Utilities 2014 Long Term Resource Plan Decision and Order G-189-14.
[203] PNG response to BCUC IR 39.1, Exhibit B-3, pp. 128-129.

2.5.1 British Columbia's Energy Objectives– UCA section 44.1(8)(a)

In its review of PNG's 2019 CRP, the Panel must consider the applicable of British Columbia's energy objectives, which are set out in Section 2 of the CEA. PNG states that the following energy objectives are those that are "not specifically applicable only to electricity resources."[204]

(b) to take demand-side measures and to conserve energy;
(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
(g) to reduce BC greenhouse gas (GHG) emissions;
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;
(k) to encourage economic development and the creation and retention of jobs; and
(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources.

The 2019 CRP includes an overview of PNG's current ECI programs and of its DSM Plan for the period 2020-2022 that describes an expansion of its ECI programs.[205] PNG submits that its schedule of expenditures enabling the continuation and expansion of PNG's ECI portfolio is aligned with achieving British Columbia's energy objectives that include conserving energy and reducing GHG emissions[206] and PNG describes how the applicable British Columbia energy objectives set out in Section 2 of the CEA are reflected in the 2019 CRP.[207]

GHG reductions

Section 2(g) of the CEA sets out British Columbia's GHG emissions target reductions. PNG submits that it is active in the evaluation of a broad range of pre-commercial technologies that enable many different ways to reduce emissions.[208] PNG is a participant in the Natural Gas Innovation Fund created by the Canadian Gas Association as well as the University of British Columbia Natural Gas Futures initiative, whose mandate is to investigate the sustainable development and use of gaseous fuels.[209]

PNG states that it has developed a GHG reduction plan that identifies the sources of PNG's GHG emissions, evaluates opportunities to reduce those emissions, and sets out a multi-year plan for reducing emissions from those sources.[210] PNG further states it has identified a project to replace the gas powered starter at compressor R1 with an electric starter, which is planned for 2020 and is expected to reduce annual GHG emissions by approximately 1,400 $tCO2_e$. PNG also identifies a project to replace the natural gas actuated controllers, which is planned for 2021 and is expected to reduce annual GHG emissions by 35 $tCO2_e$.[211] PNG has identified additional opportunities for reducing emissions from its facilities and submits that they will identify the timing of these projects in more detail in subsequent RRAs and, if necessary, CPCN applications.[212]

[204] Exhibit B-1, p. 14.
[205] Exhibit B-1, p. 14.
[206] Exhibit B-1, Cover Letter, p. 3.
[207] Exhibit B-1, pp. 14-15.
[208] Exhibit B-1, p. 64.
[209] Exhibit B-1, p. 64.
[210] Exhibit B-1, p. 71.
[211] Exhibit B-5, Response to BCSEA IR 18.4 and 18.5.
[212] Exhibit B-3; response to BCUC IR 14.1.

PNG submits it is aware of FortisBC Energy Inc.'s (FEI) '30BY30 Target', which aims to reduce GHG emissions associated with customers' energy use by 30 percent by 2030 and PNG is evaluating whether to adopt a similar target to reduce GHG emissions associated with customers' energy use.[213]

Fuel Switching

Section 2(h) of the CEA establishes the objective of encouraging the switching from one kind of energy source or use to another that decreases GHG emissions in British Columbia. In order to meet this objective, PNG describes its CNG/LNG and natural gas for transportation strategies in Sections 4.1 and 4.2 of the Application.

PNG submits that it is exploring the opportunity to leverage its existing pipeline transmission and distribution systems to provide service to micro-scale producers of CNG and LNG near demand loads and to develop new CNG and LNG distribution services to its customers.[214] PNG also states:

> …promoting CNG and LNG as an alternative to diesel, gasoline and propane for transportation, off-grid power generation and for isolated communities and large customers unattached to the utility's natural gas distribution or transmission system improves the economics of these end-uses while at the same time reduces greenhouse gas emissions through the displacement of higher carbon-content fuels.[215]

PNG also states that "promoting CNG and LNG as an alternative to diesel, gasoline and propane for transportation, off-grid power generation and for isolated communities and large customers unattached to the utility's natural gas distribution or transmission system improves the economics of these end-uses while at the same time reduces greenhouse gas emissions through the displacement of higher carbon-content fuels."[216]

PNG submits that it has evaluated the cost of building, installing and operating LNG storage and gasification facilities to serve customers in remote communities. PNG indicates that it has found that the cost of providing LNG service to these customers is currently less competitive than the existing propane supply, largely due to the high cost of transportation of the LNG from one of only two LNG liquefaction plants located in British Columbia or from one LNG facility located in northern Alberta. PNG notes that recent interest in the PNG RECAP program by micro project developers may result in the development and construction of one or more of these micro LNG production facilities within PNG's service territory. If so, PNG submits that the costs of LNG transportation may be significantly reduced thereby making LNG a more viable alternative to propane.[217]

PNG submits that it is in preliminary discussions with a few small communities surrounding Fort St. John and Dawson Creek, and in the rural regions of PNG-West, regarding the provision of natural gas distribution service, either through a pipeline connection or through LNG deliveries. PNG declined to identify the specific communities at this time.[218]

Renewable Natural Gas

Section 2(j) of the CEA sets out the objective of reducing waste by encouraging the use of waste heat, biogas and biomass. PNG presents its Renewable Natural Gas (RNG) strategy in the 2019 CRP and states that its strategy includes acquiring quantities of RNG supply from landfills and bio-digesters for delivery to PNG's customers.[219]

[213] Exhibit B-5, Response to BCSEA IR 3.1, 3.2.
[214] Exhibit B-1, p. 15.
[215] Exhibit B-1, p. 15.
[216] Exhibit B-1, p. 15.
[217] Exhibit B-3, Response to BCUC IR 9.2.
[218] Exhibit B-3; Response to BCUC IR 9.1.
[219] Exhibit B-1, p. 15.

PNG identifies common sources of biogas which includes on-farm digesters, centralized digesters, municipal or regional landfills, and municipal sewage treatment digesters and indicates that while all of these sources are available in PNG's service area, the quantities available may be insufficient to support a project that delivers RNG into PNG's distribution systems.[220] PNG states that sources of RNG supply that could be connected to PNG's system are from smaller projects that are challenging to develop at RNG prices under $30 per GJ[221], as set out in section 2(3.8)(a) of the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR).[222] In addition, PNG states that regions where RNG may be generated often lie at the ends of PNG's gas distribution system, which may lead to a need for system reinforcements, further increasing the cost of RNG supply.[223]

The CleanBC Plan includes a target to make residential and industrial natural gas consumption cleaner by putting in place a minimum requirement of 15 percent to come from renewable gas by 2030.[224] PNG states that accessing sufficient supplies of RNG to meet a five percent blend, let alone a 15 percent blend, has proved challenging for FEI and PNG expects its own efforts will be equally challenging, if not more so.[225]

PNG states that in light of these challenges, PNG anticipates the need to access alternative sources of RNG supply if it is to be successful in achieving the CleanBC Plan RNG targets. PNG has identified these alternative sources as off-system supply and emissions credits, syngas, hydrogen, and differentiated natural gas.[226]

PNG states that while it has not yet identified specific opportunities for acquiring RNG,[227] PNG anticipates adopting and filing for approval with the BCUC, a set of principles governing its ability to develop RNG supply infrastructure in Q2 or Q3 of 2020.[228]

Panel Discussion

There is no specific reference to emissions credits, syngas, hydrogen, and differentiated natural gas within the greenhouse gas reduction measures set out in the CEA, under the GGRR or in the UCA. Subsections 18(2) and (3) of the CEA set out the BCUC's powers in setting rates in relation to prescribed undertakings. The Panel notes that any project or agreement whereby PNG seeks to purchase RNG requires PNG to file the energy supply contract with the BCUC to be reviewed pursuant to section 71 of the UCA and the relevant provisions of the CEA or GGRR. The Panel encourages PNG to prepare itself for the CleanBC Plan goal of using 15% renewable gas by 2030, but acknowledges this is not yet a legislated standard.

Economic Development

Section 2(k) of the CEA establishes the objective to encourage economic development and the creation and retention of jobs.

PNG states:

> PNG-West is on the cusp of economic change due to potential opportunities for the export of LNG to Asian markets and also due to the significant infrastructure required to implement these opportunities. PNG continues to work with potential partners on LNG projects utilizing PNG's

[220] Exhibit B-1, pp. 64-65.
[221] Exhibit B-1, p. 66.
[222] *Clean Energy Act,* Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, s. 2(3.8)(a).
[223] Exhibit B-1, p. 66.
[224] CleanBC Plan, pp. 8-9.
[225] Exhibit B-1, p. 65.
[226] Exhibit B-1, p. 66-68.
[227] Exhibit B-3; Response to BCUC IR 13.4.2.
[228] Exhibit B-3; Response to BCUC IR 13.2.

transmission assets, and to monitor for opportunities to provide service to other parties that may require service during the development stage of these projects.[229]

Positions of the Parties

BCSEA submits that it supports PNG's participation in industry and academic programs developing innovative pre-commercial technologies.[230] Regarding PNG's GHG Reduction Plan, BCSEA submits that it commends this initiative. BCSEA notes that PNG provided descriptions of the timeframe and cost estimates for implementation of GHG reduction actions including the replacement of the gas-powered starter at compressor R1 with an electric starter and the replacement of the natural gas actuated controllers.[231]

BCSEA submits that it supports PNG's development of an RNG program as a mechanism for reducing British Columbia's GHG emissions.[232]

BCOAPO submits that it has some concerns regarding PNG's RNG program, specifically relating to PNG's intention to purchase the environmental attributes of RNG produced in other jurisdictions. BCOAPO further outlines a hypothetical RNG procurement scenario where PNG contracts with a third party to purchase RNG anywhere in the world and set up the contractual paths so as to capture the emission reduction benefits on behalf of PNG and its customers. BCOAPO does not believe that such a procurement scenario is in the spirit of British Columbia's Energy Objectives that include the GGRR voluntary five percent RNG target and the CleanBC Plan 15 percent RNG goal by 2030.[233]

PNG Reply Submission

In reply to BCOAPO's concern regarding procurement of RNG, PNG submits that such a procurement scenario is not currently possible as there is currently no international market for carbon emission reduction credits.[234] PNG submits that the overarching goal of the GGRR and the CleanBC Plan is to reduce GHG emissions and that reducing emissions from sources outside of British Columbia does not diminish the impact that those reductions have on global warming. PNG notes that while it is currently not proposing to acquire carbon emission reduction credits from international markets, PNG will balance the interests of developers of RNG projects in British Columbia, with the interests of its customers and seek out the most economical and cost-effective means to reduce GHG emissions.[235]

Panel Determination

The Panel is satisfied that PNG has presented an RNG strategy, though it is somewhat undeveloped. The Panel supports PNG's stated intention to adopt a set of principles governing its ability to develop RNG supply infrastructure, and notes that PNG will seek BCUC's approval of these principles. However, PNG did not achieve its filing target of Q2 or Q3 of 2020, as anticipated. **The Panel directs PNG to file a set of principles regarding the development of RNG supply infrastructure no later than the filing of its next long-term resource plan and ECI application in 2023.**

2.5.2 Adequacy & Cost-Effective DSM Measures – UCA section 44.1(8)(c)

In addition to the BC energy objectives the Panel must consider, pursuant to section 44.1(8)(c) of the UCA, whether the long-term resource plan shows that the utility intends to pursue adequate, cost-effective demand-side measures.

[229] Exhibit B-1, p. 15.
[230] BCSEA Final Argument, para. 84.
[231] BCSEA Final Argument para. 81.
[232] BCSEA Final Argument para. 83.
[233] BCOAPO Final Argument, p. 5.
[234] PNG Reply Argument, para. 18.
[235] PNG Reply Argument, para. 19.

The tests for "adequate" and "cost-effective" demand-side measures are outlined in sections 3 and 4 respectively of the Demand-Side Measures Regulation (DSM Regulation)[236]. Section 3 of the DSM Regulation outlines specific types of DSM measures that a long-term resource plan must include to be considered adequate, including measures that target low income households and the development of codes and standards.

Section 4 of the DSM Regulation explains the cost-effective tests that are applied to determine the costs and benefits of DSM. Cost effectiveness is explained in further detail in subsection 3.4.3 of this decision.

In this Application, PNG has proposed an ECI portfolio that forms part of its 2019 CRP (the reference DSM scenario) filed under section 44.1 of the UCA. PNG also requires separate approval for an expenditure schedule for the same ECI portfolio under section 44.2 of the UCA. This results in an overlap in the Panel's review of the respective approvals sought.

Typically, DSM reviews under UCA section 44.2 are undertaken at a more granular level than for UCA section 44.1 reviews. While the cost effectiveness provisions of the DSM Regulation apply directly to sections 44.1 and 44.2 of the UCA, the adequacy requirements apply directly to section 44.1 only, although utilities generally seek to align their DSM expenditure schedules with the adequacy requirements.

To avoid duplication in this decision, the Panel addresses adequacy in this section of the decision and undertakes a more detailed analysis of cost-effectiveness in subsection 3.4.3 of the decision. However, the applicable evidence and discussion apply equally to the Panel's review of both sections 44.1 and 44.2 of the UCA.

2.5.2.1 Programs to Meet Adequacy Requirements

PNG submits it has maintained and expanded its existing DSM programs that, collectively, meet the adequacy requirements of the DSM Regulation. The BCUC approved expenditures related to these programs for the period 2016 through 2018 by Order G-115-15.

PNG notes that amendments to the DSM Regulation that came into force on March 22, 2017 included additions to the adequacy requirements that specify support for the development of standards related to energy conservation and energy efficiency, and promote the adoption by local governments and First Nations of the Energy Step Code. In its ECI Funding Application, PNG includes additional measures to address amendments to the DSM Regulation, which were approved by Order G-121-19.[237] In Table 4 of Appendix F in the Application, PNG outlines each of the adequacy requirements under section 3 of the DSM Regulation and the corresponding program which PNG submits meets the respective requirement.[238]

Pursuant to Section 3(e) of the DSM Regulation, one of the adequacy requirements is:

> …one or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than
>
> > (i) an average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or

[236] Demand-Side Measures Regulation (B.C. Reg. 117/2017), (https://www.bclaws.ca/civix/document/id/complete/statreg/10_326_2008).
[237] Exhibit B-1, Appendix F, p. 45.
[238] Exhibit B-1, Appendix F, pp. 19-20.

(ii) an average of $2 million per year over the portfolio's period of expenditures; [Emphasis added].

In Section 1 of the DSM Regulation, paragraph (e) of "specified demand-side measure" means:

(e) financial or other resources provided

(i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

(ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province;

PNG submits that its Support for Training of New Home Contractors program (also referred to as Codes and Standards program) meets requirement 3(e) of the DSM Regulation,[239] and meets the requirement of an average of 1% of the portfolio's expenditures per year as illustrated below:

DSM Reg Codes and Standards Compliance (1% of proposed expenditures)	2020	2021	2022
Proposed Expenditures	$ 781,000	$ 880,100	$ 907,100
Codes and Standards	$ 10,000	$ 10,000	$ 10,000
C&S as % of Proposed Expenditures	1.28%	1.14%	1.10%

PNG describes the program as follows:

In collaboration with the CEA, BC Institute of Technology (BCIT), and local governments, PNG is supporting the delivery of workshops in its service areas, aimed at training local builders, tradespeople and building officials on how to build to the BC Energy Step Code. A BCIT instructor will use the institution's zero emissions building (ZEB) lab-in-a-box to deliver hands on high performance building training in the communities served by PNG. [240]

2.5.2.1 Cost-effectiveness of PNG's DSM Plan

In subsection 3.4.3 of this decision, the Panel discusses the cost effectiveness and makes a determination on the 2020-2022 ECI expenditure schedule. As the reference DSM scenario applicable to the 2019 CRP is simply an extension of the 2020-2022 ECI expenditure schedule, **the Panel finds that PNG's DSM Plan shows that it intends to pursue adequate cost-effective demand-side measures pursuant to section 44.1(8)(c) of the UCA.**

2.5.1 The Interests of Persons in British Columbia who receive or may receive service – UCA section 44.1(8)(d)

PNG submits that its 2019 CRP is in the public interest and in the interests of persons who receive or may receive service from PNG. PNG states it has prepared forecasts of demand that help guide it when making prudent decisions on expanding the capacity of its natural gas distribution systems, and on securing a diverse portfolio of supply resources to ensure safe, reliable service at the lowest possible cost.[241]
BCSEA considers that the 2019 CRP is in "the interests of persons in British Columbia who receive or may receive service from the public utility, in the words of section 44.1(d) of the UCA."[242]

[239] Exhibit B-3, Response to BCUC IR 42.1.
[240] Exhibit B-1, Appendix F, p. 42.
[241] Exhibit B-1, Cover Letter, p. 3.
[242] BCSEA Final Argument, para 85, p. 21.

Having reviewed the forecasts of demand included in the 2019 CRP that will help guide PNG in making prudent decisions on any expansion of capacity on its system and on securing a diverse supply resource portfolio to provide safe, reliable service at the lowest possible cost, **the Panel finds that the 2019 CRP is in the interests of persons who receive or may receive service from PNG pursuant to section 44.1(8)(d) of the UCA.**

2.6 Is the 2019 CRP in the public interest?

PNG submits that in order to make its determination that the 2019 CRP is in the public interest, the BCUC must also determine that the 2019 CRP is consistent with the requirements of section 19 of the CEA which requires a public utility to "pursue actions to meet the prescribed targets in relation to clean or renewable resources". It further submits that in section 4 of the Application, PNG presents its strategy for acquiring RNG that is consistent with the prescribed undertaking of section 3.8 of the GGRR.[243]

PNG submits that the 2019 CRP meets the requirements of section 44.1(8) of the UCA and is in the public interest, and in the interests of persons who receive or may receive service from PNG.[244] PNG states that its 2019 CRP:

> (i) defines six resource planning objectives, including alignment with the BC Energy Objectives, and describes how each of the applicable BC Energy Objectives are taken into consideration;
>
> (ii) is consistent with the requirements of the CEA and presents a strategy for acquiring RNG that is consistent with the prescribed undertaking of section 3.8 of the GGRR;
>
> (iii) summarizes PNG's DSM plan related to the ECI portfolio from 2020 to 2022; and
>
> (iv) provides forecasts of demand that help guide its decisions related to expanding capacity and on securing a diverse portfolio of supply resources to ensure safe, reliable service at the lowest cost possible and is in the interests of persons who receive or may receive service from PNG.[245]

PNG submits that the 2019 CRP meets the requirements of section 44.1(8) of the UCA and is in the public interest and should be accepted.[246]

Positions of the Parties

BCOAPO submits that it accepts that carrying out the 2019 CRP would be in the public interest as it meets the requirements of section 44.1(8) of the UCA.[247]

BCSEA submits that the BCUC should determine that carrying out PNG's 2019 CRP would be in the public interest, and accept the plan under section 44.1(6)(a).[248]

Overall Panel Determination on Acceptance of the 2019 CRP

In accordance with subsection 44.1(8) of the UCA, in determining whether to accept PNG's 2019 CRP, the Panel must consider British Columbia's energy objectives, the extent to which the plan is consistent with prescribed targets for clean or renewable resources, whether the CRP shows an intent to pursue adequate, cost effective DSM, and the interests of those who receive or may receive service from PNG. In its review of the evidence

[243] Exhibit B-1, Cover Letter, p. 2-3.
[244] PNG Reply Argument, p. 8.
[245] PNG Final Argument, pp. 7-8.
[246] PNG Final Argument, para. 25.
[247] BCOAPO Final Argument, p. 5.
[248] BCSEA Final Argument p. 22.

summarized above, the Panel has considered each of these factors and makes the following findings and determinations with respect to the 2019 CRP.

The Panel is satisfied that PNG has fulfilled the requirements of section 44.1(8) of the UCA by taking steps to reduce GHG emissions as required by British Columbia Energy Objectives as defined in section 2(b), (d), and (g) of the CEA. With respect to British Columbia's Energy Objectives as defined in section 2(h), (i) and (l) of the CEA, PNG indicates that it has made an effort to work with small communities in its service area on energy conservation, fuel switching, and the development of renewable resources, but the Panel notes that while efforts are on-going, the outcomes remain uncertain and PNG is encouraged to monitor its efforts to ensure they are achieving the objectives. The Panel is further satisfied that PNG intends to pursue adequate, cost-effective demand-side measures, as evidenced by its ECI Funding Application filed concurrently with the 2019 CRP. As for the interests of those who receive or may receive service from PNG, the Panel is satisfied that the 2019 CRP, by providing reasonable forecasts of demand that help PNG guide its decisions related to expanding capacity and on securing a diverse portfolio of supply resources to ensure safe, reliable service at the lowest cost possible, is in the interests of persons who receive or may receive service from PNG.

After reviewing the evidence, the Panel is satisfied that PNG has met the filing requirements pursuant to section 44.1(2) of the UCA and the applicable UCA section 44.1(8) considerations support acceptance of the 2019 CRP as being in the public interest**. Therefore, the Panel finds that PNG's 2019 CRP is in the public interest and accepts the 2019 CRP in accordance with section 44.1(6) of the UCA.**

2.7 Filing of Next LTRP

Section 44.1(2) of the UCA states that a utility must file a long term resource plan "in the form and at the times the commission requires."

Panel Determination

The Panel notes neither PNG nor the interveners provided submissions on an appropriate filing date for the next CRP. The Panel also notes that a number of PNG's assumption are impacted by its DSM, which is dependent on ECI programs spanning 3 years. Furthermore, given PNG must complete a REUS in advance of its next CRP, the Panel is of the view that PNG's next long-term resource plan be filed at a time when the outcomes of ECI programs and the results of the next REUS can be reflected within that plan. **The Panel therefore directs PNG to file its next long-term resource plan no later than December 31, 2023.** Following the submission of PNG's next long-term resource plan, the Panel reminds PNG that it is required to file a long-term resource plan every 5 years, pursuant to Order G-140-14.

With the Panel's review of PNG's 2019 CRP complete, the Panel now reviews the merits of PNG's ECI Funding Application.

3.0 PNG's ECI Funding Application

3.1 Approvals Sought

Pursuant to section 44.2(3) of the UCA, PNG is seeking BCUC acceptance of the ECI expenditure schedule related to the ECI portfolio for 2020 expenditures that are in addition to those previously accepted by way of Order G-121-19, and for two additional years (2021 and 2022) to fund an expanded ECI portfolio.[249] For 2020, the $491,000 for which acceptance is requested is in addition to $290,000 previously accepted in the compliance

[249] Exhibit B-1, Cover letter, p. 3.

filing pursuant to Order G-121-19. Accordingly, for the 2020-2022 period, the total proposed spending is approximately $2.568 million.[250]

Table 2: Summary of DSM Expenditures[251]

Summary: New and Existing Programs and Initiatives					
Item		2020 (F/C)	2021 (F/C)	2022 (F/C)	Total (F/C)
Existing Programs and Initiatives	(a)	$ 378,800	$ 487,900	$ 514,900	$ 1,381,600
New Programs and Initiatives	(b)	$ 402,200	$ 392,200	$ 392,200	$ 1,186,600
Total Forecast Expenditures	**(c)**	**$ 781,000**	**$ 880,100**	**$ 907,100**	**$ 2,568,200**
Approved Expenditures (G-121-19)	(d)	$ 290,000	$ -	$ -	$ 290,000
Variance (Actual - Approved)	(c) - (d)	$ 491,000	$ 880,100	$ 907,100	$ 2,278,200

In addition, PNG requests BCUC approval to allow PNG the flexibility to reallocate expenditures amongst ECI programs and between program years, subject to the total amount spent by PNG on ECI activities between the date of approval and 2022 not exceeding the total amount of $2,278,000 sought in this Application, unless otherwise approved by the BCUC. PNG proposes to continue the program funding transfer rules that were approved under Order G-121-19.[252]

PNG is also seeking approval to continue to record all ECI expenditures as summarized in Table 2 of the Application[253] in a rate base regulatory asset deferral account. Lastly, PNG is seeking approval to set the amortization period for all expenditures charged to this regulatory asset deferral account to five years, consistent with the amortization period approved for ECI expenditures over the period 2019-2020 under Order G-121-19.[254]

3.2 Legislative Framework

Section 44.2(3) requires the BCUC to accept an expenditure schedule if it considers that making the expenditures would be in the public interest, or to reject the expenditure schedule. Section 44.2(4) provides that the BCUC may accept or reject part of an expenditure schedule.

In determining whether to accept PNG's DSM Expenditure Schedule, section 44.2(5) of the UCA requires the BCUC to consider the following, explored in section 3.4 below:

(a) the applicable of British Columbia's energy objectives;

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any;

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any; and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

[250] BCSEA Final Argument, p. 8.
[251] Exhibit B-1, p. 130.
[252] Exhibit B-1, Cover letter, p. 3.
[253] Exhibit B-1, Cover letter, p. 3.
[254] Exhibit B-1, Cover letter, p. 3.

3.3 ECI Application Overview

The following table summarizes PNG's actual expenditures from inception in 2016, as well as expenditures forecast for the 2020 to 2022 period covered by the proposed plan.

Table 3: PNG ECI Program Portfolio Expenditures Summary : New and Existing Programs and Initiatives (actuals and forecast)[255]

Summary: New and Existing Programs and Initiatives								
Item	2016	2017	2018	2019	2020	2021	2022	Total
Actual/Forecast Expenditures	(Act)	(Act)	(Act)	(F/C)	(F/C)	(F/C)	(F/C)	(F/C)
Existing Programs and Initiatives	$ 215,244	$ 70,696	$ 126,543	$ 330,733	$ 378,800	$ 487,900	$ 514,900	$ 2,124,816
New Programs and Initiatives	$ -	$ -	$ -	$ -	$ 402,200	$ 392,200	$ 392,200	$ 1,186,600
Total Actual/Forecast Expenditures	**$ 215,244**	**$ 70,696**	**$ 126,543**	**$ 330,733**	**$ 781,000**	**$ 880,100**	**$ 907,100**	**$ 3,311,416**
Approved Expenditures	$ 432,403	$ 317,039	$ 349,024	$ 342,000	$ 290,000	$ -	$ -	$ 1,730,466
Variance (Actual - Approved)	$ (217,159)	$ (246,343)	$ (222,481)	$ (11,267)	$ 491,000	$ 880,100	$ 907,100	$ 1,580,950

The proposed ECI portfolio includes residential, commercial, and education and outreach programs.[256] While PNG submits that the commercial program can be accessed by PNG's industrial customers, the existing and proposed initiatives within the commercial program are most applicable to small and larger commercial customers.[257]

By Decision and Order G-121-19, the BCUC accepted PNG's 2019-2020 DSM expenditure schedule with the exception of spending on the Residential Furnace and Boiler Replacement Program due to its projected 'limited impact on energy savings' and 'tenuous cost-effectiveness indicators' relative to other measures identified in the 2017 CPR. In addition, the BCUC directed PNG to include in its next DSM plan a review and discussion of programs for new construction, under-served markets, and cost-effective programs identified in the 2017 CPR.[258]

In response to this directive,[259] PNG proposes the addition of two new ECI programs: Residential Efficient Heating and Commercial HVAC Controls.[260] These are explored further in their respective program areas below.

Residential Programs

PNG's existing residential offering consists of the Energy Conservation Assistance Program (ECAP) and Energy Saving Kits (ESK), in response to the adequacy requirements to provide demand side measures for low income households. These programs were first approved by Order G-140-14 and Order G-203-15A as meeting the low-income adequacy requirement of the DSM Regulation.

In addition to these two existing programs, PNG proposes adding a new program, the Residential Efficient Heating program, to provide incentives to residential customers to maintain their natural gas heating system. Customers may apply to receive a furnace tune up and an installed smart thermostat. The Residential Efficient Heating program is designed to improve the visibility and satisfaction of PNG's ECI programs by appealing to a broad segment of PNG's residential customers. A furnace tune up and smart thermostat were identified in the 2019 Customer Attitude Survey as the top programs or services that PNG could offer to help customers reduce

[255] Exhibit B-1, Appendix F, p. 30.
[256] Exhibit B-1, Appendix F, p. 30.
[257] Exhibit B-1, p. 131.
[258] Decision accompanying Order G-121-19 , p. 25.
[259] Exhibit B-1, Appendix F, pp. 21-23.
[260] Exhibit B-1, Appendix F, DSM Plan, p. 2.

their energy use.[261] These results are consistent with the findings of the 2017 CPR, that determined that smart thermostats offer the third highest potential energy savings in the residential sector.[262] PNG estimated the Modified Total Resource Cost (mTRC) for the new Residential Efficient Heating program, which is an adjusted cost-effectiveness measure of a DSM program, at an mTRC of 2.53. Cost-effectiveness is further discussed in subsection 3.4.3 of this decision. Forecast residential program expenditures and cumulative annual demand reductions are shown in Table 4 below:

Table 4: Proposed Residential Program Area Expenditures[263]

Residential Program Summary							
Program	Forecast Participant	Forecast Expenditures			Cumulative Annual Savings (GJ)		
		2020	2021	2022	2020	2021	2022
Efficient Heating	400	$ 193,700	$ 188,700	$ 188,700	1,224	3,672	6,120
Energy Conservation Assistance Program	100	$ 48,500	$ 48,500	$ 48,500	1,100	1,833	2,566
Energy Saving Kits	381	$ 12,900	$ 12,900	$ 12,900	4,054	5,083	6,111
Total	881	$ 255,100	$ 250,100	$ 250,100	6,378	10,587	14,797

Commercial program

PNG's current commercial energy efficiency program area includes Efficient Boilers; Efficient Water Heaters; and Efficient Kitchens programs.[264]

PNG proposes a new HVAC Controls program to provide incentives up to 50 percent of the cost to commercial business owners who upgrade their HVAC Controls. The HVAC Controls program is designed to appeal to all of PNG's commercial customers and serve as a flagship program to focus communications, increase awareness and draw in participants to other programs. According to the 2019 Customer Attitudes Survey, a program to install or upgrade building automation controls, and a program to upgrade HVAC controls both resulted in relatively high levels of interest from commercial survey respondents, at 19 and 17 percent, respectively. PNG estimates that most of the gas energy savings from "Building Automation Controls" comes from HVAC control upgrades. The CPR lists "HVAC Control Upgrades - Direct Digital Data Control" as having the second highest market potential. PNG estimates a TRC of 1.56 and an mTRC of 9.17 for the program.[265] Forecast commercial program expenditures and cumulative annual demand reductions are shown in Table 5 below:

Table 5: Proposed Commercial Program Area Expenditures[266]

Commercial Program Summary							
Program	Forecast Participant	Forecast Expenditures			Cumulative Annual Savings (GJ)		
		2020	2021	2022	2020	2021	2022
HVAC Controls	5% of floor space	$ 208,500	$ 203,500	$ 203,500	5,711	17,133	28,555
Efficient Boilers	4	$ 51,000	$ 51,000	$ 51,000	4,925	8,209	11,493
Efficient Water Heaters	16	$ 49,200	$ 49,200	$ 49,200	320	832	1,344
Efficient Kitchens	100	$ 48,700	$ 48,700	$ 48,700	729	1,629	2,529
Total	120	$ 357,400	$ 352,400	$ 352,400	11,685	27,803	43,921

[261] Exhibit B-1, Appendix F, DSM Plan, p. 31. According to p. 25 of the Customer Attitudes Survey (Appendix IV to Appendix F) 53 percent of residential customers expressed in interest in a furnace tune-up, while 34 percent expressed interest in a smart thermostat.
[262] Exhibit B-1, Appendix F, DSM Plan, p. 31.
[263] Exhibit B-1, Appendix F, DSM Plan, p. 35.
[264] Exhibit B-1, Appendix F, DSM Plan, p. 36.
[265] Exhibit B-1, Appendix F, DSM Plan, pp. 36-37.
[266] Exhibit B-1, Appendix F, DSM Plan, p. 41.

Conservation Education and Outreach programs

PNG's Conservation Education and Outreach (CEO) program area encompasses existing CEO programs, as well as two more recent programs to support training of building contractors and to support the adoption of innovative technology by PNG's customers[267] which were first approved in Order G-121-19 as part of PNG's continuing efforts to meet these particular adequacy requirements of the DSM Regulation.[268]

Table 6 provides a program summary for the conservation education and outreach program. The expenditures for the conservation and education programs are primarily related to fixed program development costs.[269]

Table 6: Proposed Conservation Education and Outreach Program Area Expenditures[270]

Conservation Education and Outreach	2016 (Act)	2017 (Act)	2018 (Act)	2019 (F/C)	2020 (F/C)	2021 (F/C)	2022 (F/C)	Total (F/C)
K-12 Conservation Education and Outreach	$ 6,570	$ 24,774	$ 26,445	$ 39,983	$ 60,000	$ 60,000	$ 60,000	$ 277,772
Post-Secondary Conservation Education and Outreach				$ 24,000	$ 24,000	$ 31,700	$ 31,700	$ 111,400
General Conservation Education & Outreach		$ 4,838	$ 15,040	$ 85,800	$ 33,500	$ 115,900	$ 92,900	$ 347,978
Codes and Standards Support				$ 14,052	$ 10,000	$ 10,000	$ 10,000	$ 44,052
Innovation				$ 35,000	$ 35,000	$ 50,000	$ 50,000	$ 170,000
Enabling Activities	$ 202,770	$ 28,668	$ 62,985	$ 6,000	$ 6,000	$ 10,000	$ 60,000	$ 376,423

Positions of the Parties

BCSEA does not take issue with PNG's responses to the topics the BCUC directed PNG to examine[271] with regards to new construction, under-served markets, and programs identified in the 2017 CPR.

BCSEA supports PNG's Natural Gas Innovation Fund and believes the proposed funding level in the 2020-2022 DSM Expenditure Schedule is reasonable.[272]

Neither BCOAPO nor BCSEA object to these proposed new programs, or to the continuation of PNG's existing ECI programs.

Panel Discussion

PNG has presented a suite of programs for both residential and commercial customers. PNG has made an effort to include a review and discussion of programs for new construction, under-served markets, and cost-effective programs. PNG has included cost-effective programs that are grounded on the 2017 CPR and 2019 Customer Attitudes Survey. The Panel encourages PNG to monitor and continue to develop these programs, and is satisfied that PNG had addressed the Directive set out in Order G-121-19.

3.4 Do the UCA Section 44.2(5) considerations support acceptance?

The Panel addresses each of the UCA section 44.2(5) considerations in turn below, before making a final determination.

3.4.1 British Columbia Energy Objectives

PNG estimates the net cumulative natural gas savings and GHG reductions over the life of measures installed over the period from 2020 to 2022 to be 793 TJ and 44,000 tonnes respectively, as shown in the table below.[273]

[267] Exhibit B-1, Appendix F, p. 29.
[268] Decision accompanying Order G-121-19, pp. 14-15.
[269] Exhibit B-1, Appendix F, p. 43.
[270] Exhibit B-1, Appendix F, p. 43.
[271] BCSEA Final Argument, p. 11.
[272] BCSEA Final Argument, p. 14.
[273] Exhibit B-1, Appendix F, p. 45.

Table 7: ECI Portfolio Energy Savings and GHG Reductions [274]

Measure		Gas Savings (over life)	GHG Reduction (over life)
Sector	**Name**	**GJ**	**tonnes**
Residential	Efficient Heating	76,745	4,298
Low Income	ECAP *	26,388	1,478
Low Income	ESK *	22,529	1,262
Commercial	HVAC Controls	462,594	25,905
Commercial	Efficient Boilers	161,553	9,047
Commercial	Efficient Hot Water Heaters	16,358	916
Commercial	Efficient Kitchens	27,000	1,512
Subtotal	**Incentive Programs**	**793,166**	**44,417**
Education	K-12	-	-
Education	Post Secondary	-	-
Outreach	General	-	-
Codes and Standards	Support for Codes and Standards	-	-
Innovation	Innovation	-	-
Admin	Enabling Activities	-	-
Portfolio Total		**793,166**	**44,417**

PNG submits that its schedule of expenditures enabling the continuation and expansion of PNG's ECI portfolio is aligned with achieving British Columbia's energy objectives that include conserving energy and reducing GHG emissions.[275]

Positions of the Parties

BCSEA is satisfied that PNG's 2020-2022 DSM Expenditure Schedule is consistent with and supports the relevant British Columbia energy objectives set out in the CEA, in particular taking demand-side measures and conserving energy and reducing BC GHG emissions.[276]

3.4.2 Most recently filed LTRP

Section 44.2(5)(b) of the UCA requires the BCUC to consider the utility's most recently filed long-term resource plan in its review of DSM expenditure schedules.

PNG submits that it has reflected the forecast impact of its proposed ECI portfolio in its demand forecasts presented in Section 8 of the 2019 CRP and therefore, the proposed schedule of expenditures is consistent with PNG's 2019 CRP.[277]

Positions of the Parties

BCSEA submits that this requirement is automatically met because PNG's long-term resource plan and DSM expenditure schedule are filed together and are being reviewed in the same proceeding.[278]

3.4.3 Cost Effectiveness of Demand Side Measures

Section 44.2(5)(d) of the UCA states that, for expenditure schedules including DSM, the BCUC must consider whether the demand-side measures are cost-effective within the meaning prescribed by regulation. Section 4 of

[274] Exhibit B-1, Appendix F, DSM Plan, p. 3, Table 1.
[275] Exhibit B-1, Cover letter, p. 3; PNG Final Argument, p. 9.
[276] BCSEA Final Argument, p. 10.
[277] PNG Final Argument, p. 9.
[278] BCSEA Final Argument, p. 10.

the DSM Regulation[279] sets out the process for determining cost-effectiveness for the purposes of section 44.2(5)(d) of the UCA.

The TRC test is the primary cost-effectiveness test for the BCUC's review of DSM expenditure schedules. The TRC is the ratio that results when the value of the benefits of DSM activity, as measured by avoided energy and capacity costs as applicable, is divided by the sum of the utility and customer costs for that DSM activity. A ratio of 1.0 or more indicates that a DSM activity provides a net benefit.

Section 4 of the DSM Regulation outlines the use of a mTRC test to represent societal and non-energy benefits for adequacy programs required under Section 3 of the DSM Regulation (Section 4(2)), and for other measures which require it (Section 4(1.1)(c)). Both versions of the mTRC require the use of the Zero Emission Energy Alternative (ZEEA), represented by BC Hydro's long-run marginal cost of acquiring electricity from clean or renewable resources in British Columbia, which PNG states is $106/MWh.[280] Pursuant to section 4(1.5)(b)(iii) of the DSM Regulation, PNG may not use the mTRC test for more than 40 percent of its portfolio expenditures. The BCUC evaluates cost effectiveness at the portfolio level and at the individual program level.

PNG provides the summarized cost benefit test results for the various program areas in the table below.[281] All programs have an mTRC of greater than 1, and the portfolio as a whole has an mTRC of 1.92

Measure		Cost-Benefit Tests				
Sector	**Name**	**TRC**	**mTRC**	**PACT/UCT**	**PCT**	**RIM**
Residential	Efficient Heating	0.42	2.53	0.35	3.19	0.16
Low Income	ECAP *	0.72	5.22	0.47	5.50	0.18
Low Income	ESK *	2.40	17.80	1.54	18.03	0.25
Commercial	HVAC Controls	1.56	na	1.85	6.60	0.30
Commercial	Efficient Boilers	1.61	na	2.40	8.10	0.32
Commercial	Efficient Hot Water Heaters	0.29	1.69	0.28	2.04	0.16
Commercial	Efficient Kitchens	0.80	4.94	0.52	7.62	0.21
Subtotal	**Incentive Programs**					
Education	K-12	-	-	-	-	-
Education	Post Secondary	-	-	-	-	-
Outreach	General	-	-	-	-	-
Codes and Standards	Support for Codes and Standards	-	-	-	-	-
Innovation	Innovation	-	-	-	-	-
Admin	Enabling Activities	-	-	-	-	-
Portfolio Total		**1.92 ****		**0.79**	**5.67**	**0.28**

* Section 4 of the BC Demand-Side Measures Regulation, as amended in March 2017, requires the use of the Zero Emission Energy Alternative and a 40 percent benefit adder in calculating the mTRC for Low Income programs.

** Includes the MTRC adder for programs that require it.

PNG provides the updated assumptions used to calculate the cost benefit tests,[282] in addition to the underlying assumptions for each of the programs within the residential and commercial program areas.[283]

PNG submits that its ECI programs are cost-effective on a portfolio basis under the modified TRC test prescribed in the DSM Regulation,[284] and that all proposed programs are cost effective as measured by either the TRC test or the mTRC test.[285]

[279] B.C. Reg. 117/2017.
[280] Exhibit B-1, Appendix F, p. 26.
[281] Exhibit B-1, Appendix F, p. 48.
[282] Exhibit B-1, Appendix F, p. 26.
[283] Exhibit B-1, Appendix F, pp. 31-41.
[284] Exhibit B-1, Cover letter, p. 4.
[285] Exhibit B-1, Appendix F, p. 47.

Positions of the Parties

BCSEA is satisfied that the 2020-2022 DSM is cost-effective under the mTRC test.[286]

3.4.4 The Interests of Persons in British Columbia

Section 44.2(5)(e) of the UCA requires the BCUC to consider the interests of persons in British Columbia who receive or may receive service from the public utility, in determining whether the DSM expenditure schedule is in the public interest and should be accepted. In the Decision accompanying Order G-121-19, the BCUC discussed customer interests by considering both the effectiveness and balance of PNG's DSM portfolio:

> Effectiveness is defined as the average cost of saved energy. Balance assesses how successful the portfolio is at providing broad opportunities for customers to participate, in particular for 'hard to reach' customers not otherwise addressed by the adequacy requirements.[287]

PNG submits that the proposed schedule of expenditures is in the interests of customers and potential customers as it encourages energy efficiency and conservation, reduce GHG emissions, and is cost effective. Individual consumers that avail themselves of ECI initiatives will reduce their natural gas consumption and their natural gas bills.[288]

PNG provides the following table which outlines the estimated cost of the proposed ECI program expressed as an annual cost per customer, per GJ of energy saved, and per avoided ton of CO_2e.[289]

	2020 - 2022	
ECI spending per customer per year	$ 18.74	$/cust/year
Cost of Energy saved*	$ 2.96	$/GJ
Cost of GHG reduction*	$ 52.82	$/tonne CO_2e

PNG submits its portfolio of ECI programs is designed to find broad acceptance amongst PNG's customers, with expenditures allocated roughly equally to the residential, commercial, and education and outreach programs.[290]

PNG states that it intends to increase awareness of its ECI programs amongst its customers in order to increase participation in all of the ECI incentive programs,[291] and is working with an external partner that is experienced in marketing DSM to remote and northern communities, to define an ECI communications plan.[292]

Positions of the Parties

BCSEA notes the estimated forecast cost of energy saved over the 2020-2022 period is $2.96/GJ, substantially lower than the $7.52/GJ forecast for the 2019-2020 period that the G-121-19 panel noted was a significant improvement over the $13.84/GJ actual cost of energy saved for the 2016-2018 period. BCSEA notes it remains

[286] BCSEA Final Argument, p. 11.
[287] Decision and Order G-121-19, p. 18.
[288] Exhibit B-1, Cover letter, p. 4.
[289] Exhibit B-1, Appendix F, p. 46. Carbon dioxide equivalent or CO2e means the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas.
[290] Exhibit B-1, Appendix F, p. 46.

to be seen what the actual $/GJ cost of energy for 2020-2022 will be.[293] BCSEA concludes that the 2020-2022 DSM Expenditure Schedule meets the effectiveness criterion articulated by the G-121-19 panel.[294]

In BCSEA's view, PNG's 2020-2022 DSM Expenditure Schedule does reflect a continuing effort to broaden the range of DSM measures and to reach the 'hard to reach' customers.[295]

3.5 Is PNG's 2020-2022 ECI Expenditure Schedule in the Public Interest?

Positions of the parties

BCSEA notes the forecast expenditure for 2020 of $781,000 is more than double the 2019 forecast expenditure of $330,733.[296] BCSEA acknowledges that PNG relies on partners in the planning, promotion and delivery of its ECI programs. However, BCSEA is not convinced that PNG will be able to effectively implement an ECI program that has more than doubled in budget without more in-house staff than PNG currently devotes to DSM.[297]

BCSEA commends PNG for taking action to increase participation in its DSM programs through increased communications, but remains concerned that underspending may be a problem during the 2020-2022 period.[298]

BCSEA believes the proposed funding level in the 2020-2022 DSM Expenditure Schedule is reasonable[299] and concludes that PNG's 2020-2022 DSM Expenditure Schedule should be accepted as being in the public interest pursuant to section 44.2 of the UCA.

BCOAPO does not oppose PNG's 2020-2022 DSM Expenditure Schedule, but remains concerned about PNG's significant ECI underspending with respect to residential customers and notes that PNG's plans for the future do nothing to allay those concerns. BCOAPO notes PNG's admission that it currently has no metrics to measure customer awareness or satisfaction and urges PNG to develop some economic and efficient ways to get an estimate of customer awareness and satisfaction so it can adjust its activities to maximize the effectiveness of its ECI portfolio spending and the accompanying environmental benefits.[300]

PNG Reply Submission

PNG acknowledges the concerns of both BCOAPO and BCSEA with regards to underspending and reiterates that it is developing a communications and outreach strategy whose goal is to increase participation rates in the residential and commercial programs. PNG considers a residential program as a 'flagship' program around which an effective communications plan can be executed, and the current application proposes a residential efficient heating program that provides incentives to residential customers to maintain the efficiency of their natural gas heating system. PNG intends to design its communications and outreach strategy around the residential efficient heating program.[301]

PNG concedes that it has not developed metrics for measuring customer awareness of, or satisfaction with, PNG's ECI programs, but submits it does have information from its 2019 Customer Attitudes Survey and is prepared to develop cost effective means of monitoring customer perceptions.[302]

[293] BCSEA Final Argument, p. 12.
[294] BCSEA Final Argument, p. 12.
[295] BCSEA Final Argument, p. 12.
[296] BCSEA Final Argument, p. 9.
[297] BCSEA Final Argument, p. 15.
[298] BCSEA Final Argument, pp. 13-14.
[299] BCSEA Final Argument, p. 14.
[300] BCOAPO Final Argument, p. 6.
[301] Exhibit B-3, BCUC 1.45.2, PNG Reply Submission, p. 6.
[302] PNG Reply Submission, p. 6.

3.6 Overall Findings on PNG's 2020-2022 ECI Expenditure Schedule

Having taken into account the UCA section 44.2(5) considerations, the Panel makes its overall determinations below with respect to PNG's request for acceptance of the 2020-2022 ECI expenditure schedule.

Panel Determination

The Panel is satisfied that PNG's 2020-2022 ECI Expenditure Schedule considers British Columbia's energy objectives; is in line with PNG's most recently filed long-term resource plan, the 2019 CRP; considers the interests of persons in British Columbia who receive or may receive service from the public utility; and includes cost-effective DSM. Further, the Panel is satisfied that PNG's 2020-2022 ECI Expenditure Schedule meets the filing requirements of section 44.2(5) of the UCA. **Therefore, the Panel finds that PNG's 2020-2022 ECI Expenditure Schedule is in the public interest and accepts it as shown in Table 8 below, pursuant to section 44.2(3) of the UCA.**

Table 8: Accepted ECI Expenditure Schedule for 2020 to 2022[303]

ECI Portfolio	Forecast expenditures ($)		
	2020	2021	2022
Residential Program Area	**255,100**	**250,100**	**250,100**
Efficient Heating	193,700	188,700	188,700
Energy Conservation Assistance Program	48,500	48,500	48,500
Energy Saving Kits	12,900	12,900	12,900
Commercial Program Area	**357,400**	**352,400**	**352,400**
HVAC Controls	208,500	203,500	203,500
Efficient Boilers	51,000	51,000	51,000
Efficient Water Heaters	49,200	49,200	49,200
Efficient Kitchens	48,700	48,700	48,700
Conservation Education and Outreach Program Area	**168,500**	**277,600**	**304,600**
K-12 Conservation Education and Outreach	60,000	60,000	60,000
Post-secondary Conservation Education and Outreach	24,000	31,700	31,700
General Conservation Education and Outreach	33,500	115,900	92,900
Codes and Standards Support	10,000	10,000	10,000
Innovation	35,000	50,000	50,000
Enabling Activities	6,000	10,000	60,000
Total	**781,000**	**880,100**	**907,100**
Total 2020-2022			**2,568,200**

This accepted ECI Expenditure Schedule includes the amount of $290,000 for 2020 which was previously accepted by Order G-121-19. The Panel considers that combining the amounts accepted into one improves transparency, and simplifies PNG's annual reporting and the transfer rules addressed in subsection 3.7.1 below.

The Panel agrees with BCOAPO's observation that without specific metrics to measure customer awareness and satisfaction, it is difficult for PNG to maximize the effectiveness of its ECI portfolio spending. The Panel encourages PNG to include such metrics in its next ECI Application.

[303] Staff table compiled from Exhibit B-1, Appendix F, Tables 14; Table 19; and Table 20.

3.7 Additional Approvals Sought

3.7.1 Flexibility in the reallocation of ECI expenditures

PNG requests that the BCUC grant approval allowing PNG flexibility in the reallocation of expenditures amongst different ECI programs and between program years.[304] PNG proposes to continue the program funding transfer rules that were approved by Order G-115-15A and extended under Order G-121-19. [305] Any reallocation is subject to the total amount spent by PNG on ECI activities between the date of approval and 2022 not exceeding the total amount of $2.278 million sought in this Application, unless otherwise approved by the BCUC, namely:[306]

(i) Funding transfers under 25 percent from one approved program area to another approved program area would be permitted without prior approval of the BCUC.

(ii) In cases where a proposed transfer out of an approved program area is greater than 25 percent of that approved program area, prior BCUC approval would be required.

(iii) In cases where a proposed transfer into an approved program area is greater than 25 percent of that approved program area, prior BCUC approval would be required.

In the event that PNG spends more or less than the full approved amount for a particular year, PNG may also seek approval to have the difference allocated to the ECI program spending in the following year, subject to the total expenditures by PNG on ECI activities not exceeding the total amount sought in this Application, unless otherwise approved by the BCUC. [307]

PNG confirms that it is not requesting a change to the program funding transfer rules approved under Order 121-19.[308]

Positions of the parties

BCOAPO notes that PNG's proposal, starting at the date of approval only works if, at the time of approval, PNG has not spent any of the $491,000 incremental to that amount already approved for 2020 by Order G-121-19. Additionally, BCOAPO submits the limit of total spending not exceeding $2.278 million should start whenever the 2020 incremental spending began, not as of the date of approval of the Application (assuming such approval is forthcoming). BCOAPO states: "if this Application is approved in July 2020, PNG should not be allowed to spend $2.278 million from July 2020 to 2022 if the Utility has already exceeded the original 2020 approved amount and dipped into the incremental $491,000 in 2020. Our clients see that detail in timing as a rather significant one."[309]

Due to concerns regarding the degree of flexibility being requested by PNG, BCOAPO takes the position that for any material reallocation of ECI spending among ECI programs and program years, PNG should be required to show *ex post* that any material reallocation is in the public interest.[310] BCOAPO's concern is that the many programs could be adversely affected should PNG choose to exercise that significant "flexibility plus", particularly those few designed to assist low-income customers.[311]

[304] Exhibit B-1, Cover letter, p. 4.
[305] Decision accompanying Order G-121-19, pp. 2-3.
[306] Decision accompanying Order G-121-19, pp. 2-3.
[307] Decision accompanying Order G-121-19, pp. 3
[308] Exhibit B-3, BCUC IR 43.1.
[309] BCOAPO Final Argument, p. 7.
[310] BCOAPO Final Argument, p. 7.
[311] BCOAPO Final Argument, p. 7.

BCSEA notes that PNG is not requesting a change to the program funding transfer rules approved under Order 121-19.[312]

PNG Reply Submission

PNG submits that the purpose of the funding transfer rules approved under Order G-121-19 is to set a threshold of materiality that simplifies PNG's management of the ECI portfolio. Under the approved rules, funding transfers under 25 percent from one approved program area to another approved program area would be permitted without prior approval of the BCUC. PNG submits that BCOAPO's proposal that material reallocations should be subject to BCUC approval *ex post* is therefore unnecessary, as PNG is already required to seek BCUC approval *ex ante*, for any funding transfers exceeding the materiality threshold of 25 percent.[313]

PNG confirms that its intention with respect to its requested flexibility in the reallocation of expenditures is limited to the amount of $2.278 million requested in the expenditure schedule for which PNG requests BCUC acceptance. For clarity, PNG has projected ECI expenditures for 2020 of $781,000 of which $290,000 has been previously approved by way of Order G-121-19, with the remaining $491,000 being the subject of the current request. The effect of the BCUC granting a continuation of the program funding rules is that the reallocation of expenditures is limited to the amount of $2.568 million for the period from January 1, 2020 to December 31, 2022.[314]

Panel Determination

PNG appears to have used the terms "program" and "program area" interchangeably in its request regarding DSM funding transfers. In the Application, PNG requests "flexibility in the reallocation of expenditures amongst ECI programs and between program years" (emphasis added).[315] However, PNG also submits that under the rules approved by Order G-121-19, "funding transfers under 25 percent from one approved program area to another approved program area would be permitted without prior approval of the BCUC" (emphasis added).[316]

Programs and program areas are not the same. To reduce any possible ambiguity, the Panel will refer specifically to either program areas or to programs, depending on the context. For further clarity, PNG's program areas consist of the residential program area, the commercial program area, and the conservation education and outreach program area. Each program area consists of one or more programs, such as the efficient heating program within the residential program area.

The Panel agrees with PNG that setting a materiality threshold for funding transfers between different program areas in the same program year is a valuable way to simplify PNG's management of the DSM portfolio. The BCUC has approved similar DSM funding transfer rules for other utilities, including BC Hydro and Fortis BC. With more flexibility in their use of the approved DSM funding, utilities face fewer barriers to spending their approved DSM funds.

Further, rules which allow the transfer of approved but unspent funds of a program from one budget year to the next budget year increase the likelihood that the approved funds are actually spent on the purposes for which they were intended.

That said, the Panel considers it prudent to continue to place some restrictions on the DSM funding transfers PNG may make without prior approval from the BCUC. The Panel has accepted PNG's ECI expenditure schedule in this Application based on the specific DSM spending allocations between programs and program areas proposed by PNG. There is no certainty that the ECI expenditure schedule would have been accepted with the

[312] BCSEA Final Argument, p. 10.
[313] PNG Reply Submission, pp. 7-8.
[314] PNG Reply Submission, p. 7.
[315] Exhibit B-1, p. 4.
[316] PNG Reply, p. 8.

same overall level of DSM funding based on different spending allocations to different programs or program areas.

For these reasons, the Panel approves the following DSM funding transfer rules for PNG:

(i) Prior BCUC approval is not required for a funding transfer from one program area to another program area in the accepted expenditure schedule within the same year, if the funding transfer is less than or equal to 25% of the budget for each of the program areas.

(ii) Prior BCUC approval is required for each funding transfer from one program area to another program area in the accepted expenditure schedule, if the funding transfer is greater than 25% of the budget of either program area.

(iii) Unspent funds from a program in the accepted expenditure schedule may be transferred to the next year for spending on the same program without prior approval of the BCUC.

In the interest of ensuring greater transparency, the Panel directs PNG to report on the following in its Annual Report filed with the BCUC:

(i) all transfers of DSM funds from one program area to another program area; and

(ii) all transfers of unspent DSM funds from one program to the same program in the following year

Furthermore, the Panel wishes to address BCOAPO's "significant concern" about the total level of DSM expenditures that is being approved as a result of this Application. PNG's total DSM expenditure for 2020 to 2022 is now $2.568 million, consisting of $290,000 previously accepted by the BCUC and a further $2.278 million accepted by the Panel as a result of this Application. In section 3.6 above, the Panel accepted a consolidated ECI expenditure schedule totalling $2.568 million for the period 2020 to 2022, which includes the $290,000 previously accepted for 2020 pursuant to Order G-129-19. There is now no distinction between the previously accepted amount and the amount additionally accepted as a result of the ECI Funding Application.

3.7.2 Deferral account

PNG is also seeking approval to continue to record all ECI expenditures in a rate base regulatory asset deferral account.[317] Lastly, PNG is seeking approval to set the amortization period for all expenditures charged to this regulatory asset deferral account at five years, consistent with the amortization period approved for ECI expenditures over the period 2019-2020 under Order G-121-19.[318]

Positions of the Parties

BCOAPO agrees that PNG's proposal to record ECI expenditures in a rate base deferral account, amortized over five years, is consistent with Order G-121-19.[319]

Panel Determination

The Panel approves PNG's proposed continuation of the inclusion of ECI expenditures in a rate base deferral account. The Panel approves amounts in this deferral account to be amortized over a five-year period.

[317] Summarized in Table 2, Exhibit B-1, Cover letter, p. 3.
[318] Exhibit B-1, Cover letter, p. 4.
[319] BCOAPO Final Argument, p. 8.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of October 2020.

Original Signed By:

A. K. Fung
Panel Chair

Original Signed By:

C. Brewer
Commissioner

Original Signed By:

R. I. Mason
Commissioner

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ORDER NUMBER
G-265-20

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
Application for Acceptance of
2019 Consolidated Resource Plan and for Acceptance of
Energy Conservation and Innovation Portfolio Funding for 2020 to 2022

BEFORE:
A. K. Fung, QC, Panel Chair
C. Brewer, Commissioner
R. I. Mason, Commissioner

on October 23, 2020

ORDER

WHEREAS:

A. On October 31, 2019, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)) (collectively, PNG) filed for acceptance by the British Columbia Utilities Commission (BCUC) the 2019 Consolidated Resource Plan and expenditure schedule for the Energy Conservation and Innovation (ECI) Portfolio for 2020 to 2022 (2020-2022 ECI Expenditure Schedule), pursuant to sections 44.1 and 44.2 of the *Utilities Commission Act* (UCA) (together, the Application);

B. In the Application, PNG also seeks the following approvals:

    1. Flexibility in the reallocation of expenditures among Demand Side Management (DSM) programs and between program years, subject to the total amount not exceeding the total amount of $2,278,000, as per the 2020-2022 ECI Expenditure Schedule; and

    2. Approval to record all DSM expenditures in a rate base regulatory asset deferral account, and to retain the 5-year amortization period for DSM expenditures approved by BCUC Order G-121-19;

C. By Orders G-322-19 and G-24-20, the BCUC established a public hearing process and a regulatory timetable for review of the Application, which consisted of intervener registration, BCUC and intervener information requests (IRs), PNG responses to IRs and submissions on further process;

D. By January 17, 2020, British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and British Columbia Sustainable Energy Association (BCSEA) registered as interveners;

E. On March 16, 2020, the BCUC received submissions on further process from PNG, BCOAPO and BCSEA, all in support of proceeding to final argument;

F. By Order G-72-20, dated March 31, 2020, the BCUC amended the Regulatory Timetable to include a second round of IRs and further process to be determined;

G. On May 12, 2020, PNG filed responses to BCUC, BCOAPO and BCSEA IR No.2;

H. By Order G-121-20, dated May 22, 2020, the BCUC further amended the Regulatory Timetable to include PNG and intervener final arguments and PNG reply argument; and

I. The BCUC has completed its review of the evidence and submissions by all parties and finds that the following determinations are warranted.

NOW THEREFORE pursuant to sections 44.1, 44.2 and 99 of the UCA, and for the reasons as set out in the Decision accompanying this Order, the BCUC orders as follows:

1. PNG's 2019 Consolidated Resource Plan is accepted.

2. PNG's 2020-2022 Energy Conservation and Innovation Expenditure Schedule in the amount of $2.568 million as set out in Table 8 of the Decision is accepted.

3. PNG is directed to comply with the funding transfer rules for reallocating expenditures amongst DSM program areas and between program years as approved in section 3.7 of the Decision accompanying this Order.

4. PNG's proposed continuation of the inclusion of ECI expenditures in a rate base deferral account to be amortized over a five-year period is approved.

5. The BCUC rescinds the directive in section 9.1 of the PNG (N.E.) 2015 Resource Plan Decision accompanying Order G-155-15 requiring PNG(N.E.) to include in future resource plans an action plan consisting of the detailed acquisition steps for those resources which need to be initiated over the next four years to meet the most likely gross demand forecast as it relates to liquified natural gas and compressed natural gas. All other aspects of this directive remain in force.

6. PNG is directed to comply with all other determinations and directives as set out in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of October 2020.

BY ORDER

Original Signed By:

A. K. Fung, QC
Commissioner

Attachment

Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
Application for Acceptance of
2019 Consolidated Resource Plan and for Acceptance of
Energy Conservation and Innovation Portfolio Funding for 2020 to 2022

BCUC Directives

Page	Directive
11	**The Panel directs PNG to update the REUS no later than 2023 and include the results of the updated REUS in the demand forecast in its next long-term resource plan.**
17	**The Panel directs PNG to include more extreme planning scenarios, including the gain or loss of a large commercial or industrial customer demand as directed in Order G-140-14 in its next long-term resource plan.**
24	PNG has failed to analyze the bill impact on other customer groups as previously directed by the BCUC, and the Panel finds that PNG has only partially fulfilled the directives in Order G-155-15. **The Panel considers the missing information from Order G-155-15 is still relevant, and therefore directs PNG to include an analysis of bill and rate impacts relating to all customer groups in future DSM/ECI Plans.**
27	**The Panel finds that PNG has not fulfilled this directive in Order G-140-14 and directs PNG to file an update on all gas supply options and an examination of the merits of these options by December 31, 2022.** **The Panel directs PNG in its next long-term resource plan to provide further analysis of its resiliency plan, including supply risks and its back-up plan in the event of a pipeline rupture, loss of supplier, or similar disruption, for the PNG-West and PNG(N.E.) systems.**
30	**Accordingly, with respect to LNG and CNG, the Panel rescinds the directive at section 9.1 of the PNG (N.E.) 2015 Resource Plan Decision accompanying Order G-155-15 requiring PNG to include in future resource plans an action plan consisting of the detailed acquisition steps for those resources which need to be initiated over the next four years to meet the most likely gross demand forecast.**
36	**The Panel directs PNG to file a set of principles regarding the development of RNG supply infrastructure no later than the filing of its next long-term resource plan and ECI application in 2023.**

40	**The Panel therefore directs PNG to file its next long-term resource plan no later than December 31, 2023.**
52	**In the interest of ensuring greater transparency, the Panel directs PNG to report on the following in its Annual Report filed with the BCUC:** **(i) all transfers of DSM funds from one program area to another program area; and** **(ii) all transfers of unspent DSM funds from one program to the same program in the following year**

Order	Directive	Status	Section
G-155-15	The Panel determines that PNG(N.E.) must continue to identify and weight objectives in subsequent resource plans, irrespective of whether or not the resource plan puts forward any new projects/initiatives. PNG(N.E.) is further directed to treat those values as actuals (as opposed to hypotheticals) for purposes of evaluations of resource options. Further, the objectives and weights should typically be held consistent from one resource plan to the next, save for if and when PNG(N.E.) can substantiate in a subsequent filing the need and reasons for any changes thereto. Those objectives and weights should also be used by the Company as an important input to the evaluation of resource options put forward in the Resource Plan and/or any subsequent filings (e.g. Certificate of Public Convenience and Necessities) arising from the Resource Plan. (p. 4)	PNG will consistently apply the weightings identified in its resource planning objectives when evaluating alternatives to resource portfolios, projects or other initiatives. A review of PNG's resource planning objectives is found in Section 1.4. PNG has reviewed the weightings assigned to each of the planning objectives and amended them to reflect a greater consideration of Objective 6 - the B.C. Government's "Energy Objectives".	Section 2.3.5.1
G-155-15	The Panel directs PNG(N.E.) to also include aggregate peak day demand forecast of the system in future resource plans. The Panel considers	PNG has included a peak day sales demand aggregated across the PNG-West, Fort St. John and Dawson Creek systems in Section 9.5. The	Section 2.3.1.2

	that an aggregate peak day demand forecast would be helpful when determining gas supply requirements to meet the aggregated peak day demand.	design day sales demand, rather than the total demand of all sales and transportation customers, is relevant to determining, and contracting for, PNG's gas supply requirements.	
G-155-15	The Panel directs PNG(N.E.) to include a summary of the assessments performed and the results of such assessments PNG relied on to inform the timing of the REUS and small commercial customer survey in the next resource plan filing. (p. 8)	PNG decided not to refresh the results of the entire 2013 REUS. PNG has no indications from the year over year trend of its residential and small commercial use per accounts, that customer characteristics or end use behaviour has changed substantially. However in 2019, PNG completed a Customer Attitudes Survey targeted at both residential and commercial customers, that addressed a range of topics including attitudes and beliefs about the environment, natural gas and renewable energy; satisfaction with customer service interactions; interest in online services from PNG; participation and interest in energy-efficiency initiatives, and willingness-to-purchase natural gas augmented with biomethane. A set of questions on customers natural gas appliances and dwelling characteristics, similar to those included in the 2013 REUS, where included as well. Section 3 presents a summary of the results.	Section 2.3.1.1

G-155-15	To promote regulatory efficiency of future resource plan filings, the Panel directs PNG(N.E.) to include in its next and subsequent resource plans the following information: a. Different DSM funding scenarios which should at a minimum include a "reference" DSM funding scenario with "high DSM" and "low DSM" scenarios relative to the reference funding scenario; b. An estimate of the demand for energy that the public utility expects to serve after it has taken all reasonable cost-effective demand-side measures. Given the BC energy objective to "take demand side measures and to conserve energy," the Panel expects that PNG should be able to identify sufficient cost-effective DSM to result in a load forecast adjustment for DSM that exceeds "the precision of the forecast"; c. An analysis of each DSM funding scenario, including average bill and rate impacts for each customer class; and d. An analysis that shows how PNG has taken into account regional differences (such as different customer composition and customer preferences) in both identifying DSM	PNG presents its analysis of a "reference" and "high DSM" funding scenarios in Section 8. PNG has not included an analysis of a "low DSM" funding scenario. PNG submits that a low DSM funding scenario corresponds to a DSM portfolio that meets the adequacy requirements of the DSM Regulation only. PNG's current ECI portfolio, while it includes initiatives that go beyond the minimum adequacy requirements, has not achieved significant market penetration of its additional, commercial programs to date. Consequently, the current performance of the current ECI portfolio is considered comparable to a hypothetical "low DSM" scenario.	Section 2.3.2 Section 3.4.3

	opportunities and the extent to which DSM programs will be taken up in the different regions. (p. 10)		
G-155-15	In the next resource plan, PNG(N.E.) is directed to confirm whether or not PNG(N.E.) has been able to safely remove the operating pressure constraint on the Sunrise lateral and describe the resulting impact on capacity in the Dawson Creek operating system. The Panel is concerned that if the self-imposed limit on the operating pressure of the PennWest segment of the Sunrise lateral cannot be removed, it may present a constraint to potential new demand. (p. 11)	PNG intends to remove this self-imposed limit when and if it establishes the structural integrity of the pipeline through a corrosion survey and investigative digs. However, at this time, PNG has determined that it has sufficient capacity to reliably serve the customers of Dawson Creek. With the extension of a main in 2014, connecting the Pouce Coupe and Tomslake distribution systems, approximately half of Pouce Coupe customers are supplied from a connection to Encana's fuel gas system located to the south of Tomslake, reducing the peak day demand supplied from the PennWest lateral. The Dawson Creek distribution system is discussed further in Section 7.5.1.3.	Section 2.3.3
G-155-15	The Panel is of the view that the 2015 Resource Plan is not as thorough as it should be regarding the regional LNG and CNG strategy. As specified in the Commission's Resource Planning Guidelines, the Panel directs PNG(N.E.) to include in future resource plans an	PNG has not pursued the regional LNG and CNG strategy to any significant degree. The current state of these initiatives is discussed in Section 4	Section 2.3.5.2

	action plan consisting of the detailed acquisition steps for those resources which need to be initiated over the next four years to meet the most likely gross demand forecast. Further, the Panel reminds PNG(N.E.) of the determination noted earlier in this decision on the consistent use of objective weights when considering projects. (p. 21)		
G-140-14	The Panel finds that the inclusion in the sensitivity analyses of scenarios incorporating the gain or loss of a large commercial/industrial customer to be useful in assessing the demand on the PNG system. The Commission directs PNG to include such analyses in its next Resource Plan (p. 8)	PNG has included a sensitivity analysis of its demand forecast in Section 7.4 that reflects possible alternative forecasts of known large customer demand. PNG has not, however, otherwise assigned an arbitrary level of future demand to an unknown large customer. Due to the networked nature of PNG's distribution systems, there are many possible outcomes when a large customer requests service. In the event that the new customer's demand exceeds PNG's current capacity to serve, PNG would undertake a hydraulic analysis based on the particular load factor of that customer, and actual demand prevailing at that time. Should capital investment to expand capacity be required PNG would undertake an economic analysis to determine whether a financial contribution from	Section 2.3.1.1

		the new customer would be required in order to avoid an adverse impact on rates of existing customers. In Section 7.3.4, PNG discusses the RECAP process. PNG has not reflected any outcomes of the RECAP in any of its forecasting scenarios. At this time, PNG has no clear indication of the outcome of the RECAP and will not speculate on any likely uptake of spare capacity. At this time, the PNG-West system, as it is currently operated, has ample capacity to meet expected demand outside of the RECAP process. While PNG could reasonably include sufficient additional demand under the High Scenario that would result in a fully utilized transmission system, such a forecast provides little if any meaningful information.	
G-140-14	The Commission Panel notes that in addition to the gas supply available at Station 2, there appear to be a number of additional gas supply options on the horizon which may be beneficial to customers. PNG is directed to include an update on all gas supply options and to examine the merits of these options in its next Resource Plan. (p. 11)	In the proceeding that reviewed PNG's 2014 Resource Plan for PNG-West, PNG discussed two potential additional sources of gas supply in the future: the Merrick Mainline and the Pacific Trail Pipeline. At this time, both projects are on hold pending more favourable market conditions. With the exception of RNG which is discussed in Section 4.4, PNG has not identified any additional gas supply alternatives to those in its existing	Section 2.3.4

		gas supply portfolio.	

Forecast of Total Gross Annual Demand for PNG-West, and the Fort St. John, Dawson Creek and Tumbler Ridge service areas.[320]

Figure 43: Forecast of Total Gross Annual Demand (PNG-West)

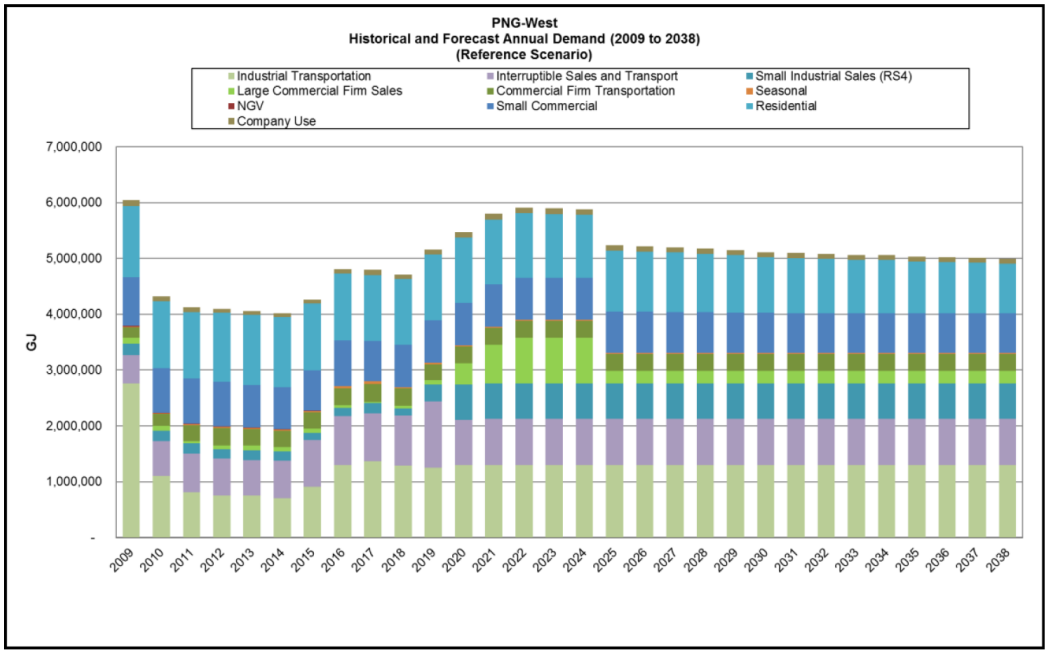
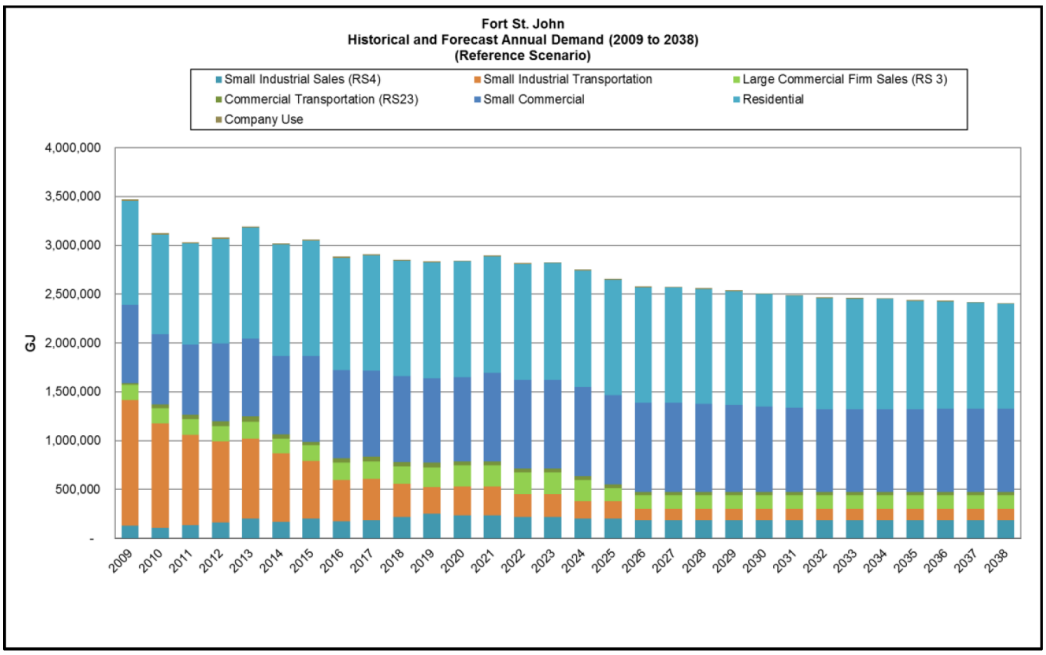


Figure 44: Forecast of Total Gross Annual Demand (Fort St. John)



[320] Exhibit B-1, Section 7.3.6, pp. 107-108.

Figure 45: Forecast of Total Gross Annual Demand (Dawson Creek)

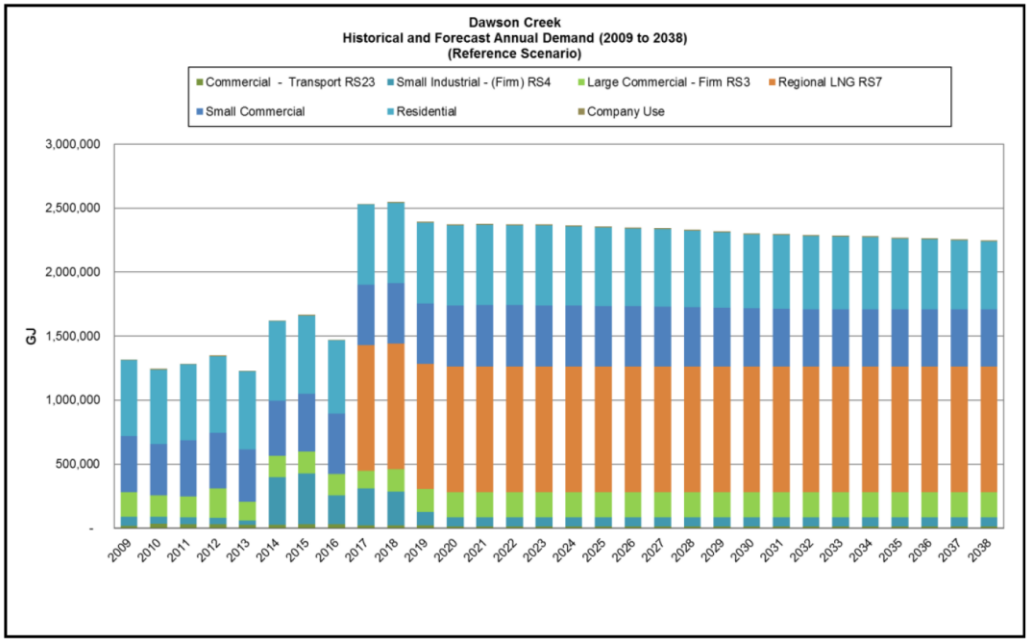


Figure 46: Forecast of Total Gross Annual Demand (Tumbler Ridge)