IN THE MATTER OF

FORTISBC ENERGY UTILITIES

2014 LONG TERM RESOURCE PLAN

DECISION

December 3, 2014

Before:

D. M. Morton, Commissioner/Panel Chair
C. A. Brown, Commissioner
H. G. Harowitz, Commissioner
I. F. MacPhail, Commissioner

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EXECUTIVE SUMMARY

The FortisBC Energy Utilities (the FEU) filed an application on March 25, 2014 for acceptance of the 2014 Long Term Resource Plan (LTRP) pursuant to section 44.1 of the *Utilities Commission Act* (UCA) (Application). The 2014 LTRP provides a high level examination of future demand and supply source expectations over the next 20-year period and outlines in broad terms the actions required over the next four-year period to ensure the energy needs of customers are met over the long-term.

The Application was reviewed by way of a written hearing process. In considering the Application, the Commission Panel must determine whether the requirements of section 44.1(2) of the *UCA* have been met. In addition, as required by section 44.1(8), consideration must be given to provisions related to British Columbia's energy objectives, the requirements of the *Clean Energy Act*, demand-side measures and public interest.

The interveners as a group supported the Commission's acceptance of the 2014 LTRP. However, British Columbia Old Age Pensioners' Organization *et al.* raised concerns about the FEU's suggestion that it may consider investing in natural gas reserves to ensure security of supply for customers. The Commercial Energy Consumers Association of British Columbia expressed concerns that the FEU's discussion related to market transformation could have been more fully developed.

The Commission Panel, after an assessment of the Application in terms of the requirements outlined in sections 44.1(2) and 44.1(8) of the UCA and the evidence before it, accepts the FEU 2014 LTRP under section 44.1(6) of the UCA as being in the public interest.

In this Decision, the Panel comments on the quality of the 2014 LTRP and has made a number of directives concerning the preparation of future resource plans in the following areas:

- The development of alternate system resource plan scenarios.
- If, in the next LTRP, the FEU provide a demand forecast that includes the possibility of there being insufficient supply for both NGT BC customers and non-BC LNG export customers, then the Panel directs the FEU to address how it will ensure compliance with section 44.1(8)(d) of the UCA.

In addition, the Commission Panel has provided a number of suggestions regarding the presentation of demand scenarios in the next LTRP.

Further, the Panel has expressed concerns about the FEU's proposal to replace its demand forecasting method with an end-use method. Specifically, the Commission Panel directs the FEU to:

- In its next LTRP filing, provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods; and
- Continue the use of the Traditional Method as a parallel approach until such time as the Commission finds a new end-use method as a substitute acceptable.

1.0 INTRODUCTION

On March 25, 2014, the FortisBC Energy Utilities (the FEU), comprised of FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW), filed their 2014 Long Term Resource Plan (2014 LTRP) pursuant to section 44.1 of the *Utilities Commission Act* (UCA) and the British Columbia Utilities Commission (Commission or BCUC) Resource Planning Guidelines (RP Guidelines) (Application).

1.1 Application

The FEU provide natural gas services to more than 945,000 residential, commercial and industrial customers in more than 135 communities throughout British Columbia. The three gas utilities provide services to the Lower Mainland, Interior of BC, Whistler, Vancouver Island, Sunshine Coast and Powell River.

The FEU 2014 LTRP present a long-term view of how the FEU will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years. The FEU 2014 LTRP discusses the planning environment; energy demand forecasting; demand-side resources; system resource needs and alternatives; gas supply portfolio planning and price risk management; stakeholder engagement and also includes a 20 year vision for the FEU and an action plan to pursue over the next four years.

The previous resource plan, Terasen Utilities 2010 Long Term Resource Plan (FEU 2010 LTRP), was accepted through Commission Order G-14-11.[1]

1.2 Orders sought

The FEU filed their 2014 LTRP for acceptance by the Commission, in accordance with section 44.1 of the UCA and the Commission's RP Guidelines.

The FEU do not seek approval of any particular elements of the plan and states that any requests for approval of specific resource needs that are identified within the 2014 LTRP will be further evaluated and brought forward to the Commission through a separate application.[2]

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[1] The FortisBC Energy Utilities (composed of FortisBC Energy Inc., FortisBC (Vancouver Island) Inc., and FortisBC (Whistler) Inc. were formerly known as Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. All Terasen matters are referred to as FortisBC Energy matters for the remainder of this decision.

[2] FEU 2014 LTRP, Exhibit B-1, p. 2.

1.3 Legislative framework

The FEU seek acceptance of the 2014 LTRP under section 44.1 of the UCA. In summary, this section of the UCA specifies what a resource plan must include and that the Commission must accept the plan if it determines that carrying out the plan would be in the public interest.

Subsection 44.1(2) of the UCA sets out that a public utility is to file with the Commission "in the form and at the times the commission requires" a long-term resource plan which includes:

- an estimate of the demand for energy the public utility would expect to serve if it does not take new demand-side management (DSM) measures during the period addressed by the plan;
- a plan of how the public utility intends to reduce its demand by taking cost-effective DSM measures and an estimate of the demand for energy that the public utility expects to serve after it has taken those measures;
- a description of the facilities that the public utility intends to construct or extend, and information regarding the energy purchases from other persons the public utility intends to make, to serve demand after all cost-effective DSM measures are taken;
- an explanation as to why the demand for energy to be served by facilities the utility intends to construct or extend and energy purchases the utility intends to make cannot be met with DSM; and
- any other information required by the Commission.

In Commission Order G-14-11, accepting the 2010 LTRP, the Commission provided a number of directions for the next FEU resource plan.

In 2003 the Commission established RP Guidelines to clarify the planning requirements of the utility under the UCA. It should be noted that sections of the UCA referred to in the RP Guidelines have been revised since issuance of the RP Guidelines in December 2003; however the spirit and substance of the RP Guidelines continue to be applicable. In particular, the Commission requires that resource plans include: identification of the planning context and the objectives of the resource plan; demand forecasts that reflect uncertainty about the future; evaluation of a range of resource portfolios (consisting of a combination of demand and supply side options) for each demand scenario; and a four year action plan for the most likely demand forecast which includes contingency plans showing how the utility would respond to changed circumstances.

Subsection 44.1(6) of the UCA gives the Commission the discretion to either accept the LTRP, if the Commission determines that to carry it out would "be in the public interest," or to reject it, subject to the discretion given the Commission in subsection 44.1(7) to accept or reject "a part" of an LTRP.

Pursuant to subsection 44.1(8) of the UCA, in determining to accept an LTRP, the factors that the Commission "must consider" include:

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

As required by the UCA (section 44.1(8)(a)), the Commission must consider the applicable of British Columbia's energy objectives in reviewing resource plans filed by utilities under its jurisdiction. Section 2 of the *Clean Energy Act* (CEA) sets out BC's energy objectives. Those most relevant to this proceeding include:

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

The Demand-Side Measures Regulation, BC Reg. 326/2008 (DSM Regulation), defines the adequacy requirements and cost-effectiveness tests to be used by the Commission in evaluating a DSM Application under subsection 44.1(8)(c) of the UCA. Ministerial Order 233 modified the DSM Regulations on June 4, 2014, amending a number of items. This included an expanded definition of 'low income household' and changing the calculation of the FEU's cost of energy for the modified Total Resource Cost Test (mTRC). The FEU submit that these changes do not result in an expansion of their Energy Efficiency and Conservation (EEC) funding request.[3]

Subsection 44.2 of the UCA sets out that a public utility may file with the Commission a demand-side measures expenditure schedule containing a statement of the expenditures the public utility has made or anticipates making during the period addressed by the schedule. Pursuant to subsection 44.2(3) of the UCA, the Commission must accept the expenditure schedule if the Commission considers that the expenditures are in the public interest. Subsection 44.2(4) allows the Commission to accept or reject a part of a schedule.

1.4 Regulatory process

The Commission Panel established a written hearing process in accordance with the Regulatory Timetable attached as Appendix A. The process included two rounds of Information Requests (IRs) prior to the final arguments phase of the proceeding.

Seven organizations registered as interveners in this proceeding:

- Aitken Creek Gas Storage ULC;
- B.C. Sustainable Energy Association and the Sierra Club British Columbia (BCSEA);
- British Columbia Hydro and Power Authority (BC Hydro);

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[3] FortisBC Energy Inc. Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2018, Decision, G-138-14, p. 255.

- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO);
- Canadian Office and Professional Employees' Union, Local 378 (COPE 378);
- Commercial Energy Consumers Association of British Columbia (CEC); and
- Just Energy (B.C.) Limited Partnership.

The following two organizations registered as interested parties in this proceeding:

- Sentinel Energy Management; and
- Ferus Natural Gas Fuels.

Among the interveners, BCSEA, BCOAPO, CEC and COPE 378 actively participated in some or all of the processes.

In a July 9, 2014 letter, BCSEA requested that the Commission Panel confirm that the following topics were within the scope of the proceeding:

i. The input assumptions for the GHGenius model and the sensitivity of the results concerning the GHG emissions, consequences of the FEU's natural gas for transportation (NGT) initiative; and

ii. GHG emissions from the FEU's own facilities, including stationary combustion, venting, flaring, fugitive methane emissions and third party line hits.

The Commission invited submissions from the FEU and registered parties regarding the request by BCSEA. After reviewing the request and the associated submissions, the Commission Panel issued an email on July 29, 2014 ruling that both topics were outside of the scope of this proceeding.

There was no intervener evidence filed. The FEU addressed intervener final arguments from BCOAPO, BCSEA and CEC in its Reply on September 17, 2014.

1.5 2010 LTRP

On February 1, 2011, the Commission issued its decision on the FEU 2010 LTRP. In that decision, the FEU 2010 LTRP was accepted by the Commission, however the 2010 Panel made it clear the plan was only adequate, and that there were many areas which could be improved in future resource plan submissions. Specifically, the 2010 Panel expressed concern over the limited number of scenarios and lack of detail for each scenario which the 2010 Panel considered fell short of providing a clear picture of the impact of the challenges faced by the company and how its plans will assist in meeting these challenges.[4]

As a result of these concerns, in the FEU 2010 LTRP Decision the 2010 Panel, pursuant to section 44.1(2)(g) of the UCA, directed that the FEU include, in the next LTRP, additional information.[5]

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[4] FEU 2010 LTRP Decision dated February 1, 2011, Order G-14-11, pp. 19–23.

[5] Ibid., pp. 23–25.

2.0 PURPOSE AND EVALUATION OF THE RESOURCE PLAN

This section of the decision will consider the specific purpose of this resource plan, in the context of the applicant and issues raised in the proceeding. In addition, this section will consider adequacy of the Application in the context of purpose as guided by the UCA.

The purpose of the LTRP process is to support utilities to develop plans that reflect their specific circumstances. From the Commission's perspective LTRPs support, in principle, regulatory efficiency. The Commission's mandate of evaluating resource plans is to "facilitate the cost-effective delivery of secure and reliable energy services" while addressing government policy.[6]

It must be emphasized that resource planning, from the Commission's perspective, is not simply a perfunctory matter whereby utilities file template material cut and pasted from annual reports available in public records. Rather, resource planning is a process requiring utilities to consider all anticipated resources required to meet the demand for a utilities product and services. The intent of resource planning is to facilitate the cost-effective delivery of secure and reliable energy services. In the words of the previous panel from the FEU 2010 LTRP, "resource plans should provide a comprehensive 20 year view of a [utility's] trajectory and provide a strong support for programs and initiatives which will be filed with the Commission."

The Panel considers that the purpose of the FEU's LTRP is to:

- Provide strategic direction and insight for future applications where the UCA specifically requires consideration of the LTRP (Certificate of Public Convenience and Necessity (section 45, UCA), Energy Supply contracts (section 71, UCA), and DSM (section 44.2, UCA));
- Provide direction on broader policy issues that may arise in other applications, such as rate design, extension policy and revenue requirement applications; and
- Identify and consider areas where there may be public interest concerns (for example, with regard to support for BC's Energy Objectives).

During the proceeding, issues were raised regarding:

1. Whether the applicant's resource plan should assess alternative resource portfolios, as suggested by the RP Guidelines.
2. Whether the FEU should connect this LTRP to its strategic plan and marketing plan.
3. Whether and/or the extent to which the FEU LTRP process can or should be used to direct the FEU's strategic planning and market strategies.
4. Whether the FEU should be directed to coordinate with BC Hydro in the development of its next LTRP in terms of its natural gas for transportation (NGT) strategy.

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[6] Resource Plan Guidelines (RP Guidelines), p. 1.

2.1 Should this resource plan assess alternative resource portfolios?

The RP Guidelines state: "In sum, a resource planning process that assesses multiple objectives and the trade-offs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service."[7] Guidance regarding the purpose and scope of the LTRP is also provided in the FEU 2010 LTRP Decision, which directed that the FEU, in the next LTRP, develop a 20-year vision for the FEU that includes business lines, customers, expectations for supply and demand, and expected major business challenges.[8]

BCUC asked whether a key purpose of a utility's "resource plan is to assess multiple objectives and trade-offs between alternative resource portfolios." While the FEU generally agreed, it opined that this differs depending on the nature of the utility. The FEU indicated that while the FEU agree that this is a key purpose for a vertically integrated public utility, this is not the case for the FEU and stated:

> 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.[9]

While BCSEA submits that the LTRP should include a comprehensive GHG analysis, it acknowledges the FEU's submissions on this issue.[10]

Commission discussion

The Commission Panel reiterates that the purpose of an LTRP is to support utilities to develop plans that reflect their particular circumstances. The approach laid out in the RP Guidelines is to develop and evaluate several plausible resource portfolios, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast. 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[11] and the addition of one significant customer can quickly overwhelm any refinement in the load forecasting approach for existing customers.

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[7] Ibid., pp. 1–2.
[8] FEU 2010 LTRP Decision, p. 24.
[9] Exhibit B-2, BCUC IR 1.1.4, p. 4.
[10] BCSEA Final Argument, pp. 4–5.
[11] Exhibit B-9, BCUC IR 2.15.1, p. 41.

The Panel considers that this portfolio approach is less appropriate for the FEU than, say, BC Hydro, as DSM, infrastructure and energy supply can generally be evaluated independently of each other. The Panel therefore considers that a tailored approach for the FEU is required to reflect its specific circumstances. The specific application of RP Guidelines will be addressed throughout the decision.

2.2 Should the FEU provide evidence of its strategic planning and strategic marketing processes?

The issue was raised as to whether the FEU should provide evidence of their broad strategic approach to the LTRP and include in the LTRP information respecting the FEU's strategic planning and marketing plans. CEC notes its request of the FEU to discuss any special strengths and weaknesses they have in meeting challenges and addressing opportunities; and a review of the plans to minimize the weaknesses, but the FEU replied that these were strategic corporate planning issues and were not part of the review of the LTRP. CEC submits that such information is highly relevant to a quality LTRP.[12]

CEC recommends that the Commission direct the FEU to include in the next LTRP, among other things, strategies for influencing markets, SWOT analysis (strengths, weaknesses, threats and opportunities), risk management analysis and further marketing analysis and technology analysis.[13]

The FEU responded to CEC's position by submitting that the Commission should reject recommendations that would transform the LTRP from a resource planning exercise into a review of the Companies' strategic planning and market strategies. The FEU submit that such a transformation is inappropriate and, if directed, these recommendations would interfere with the management function of the FEU and exceed the Commission's jurisdiction under section 44.1 of the UCA.[14]

The FEU submit:

> As the Court of Appeal made clear in the BC Hydro Decision[15], the Utilities Commission Act, when taken as a whole and viewed in the required purposive sense, does not reflect any intention on the part of the legislature to determine the manner in which the directors of a public utility manage its affairs. Section 44.1(2)(g) must be read within this context and with this purposive analysis in mind. The FEU submit that all of the CEC recommendations noted above, if directed, would trespass into the manner in which the directors of the FEU manage its affairs. Therefore, these directives cannot be issued under section 44.1(2)(g).[16]

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[12] CEC Final Argument, pp. 1–3.
[13] Ibid., pp. 25–26.
[14] FEU Reply Argument, p. 9.
[15] *BC Hydro v. B.C. (Utilities Commission)* (1996), 20 B.C.L.R. (3d) 106 (C.A.).
[16] FEU Reply Argument, p. 18.

Commission determination

The Commission Panel acknowledges the FEU's submissions that the BCUC does not have unfettered discretion to create the FEU's strategic plan. However, in the Panel's view, a utility should not create an LTRP in a vacuum. An LTRP is a document that considers demand, DSM, the construction of any facilities needed to meet demand, energy purchases necessary to meet demand, and "any other information required by the commission."[17] These are all of the fundamental elements of an LTRP. The Panel considers that a demand analysis for the purposes of the LTRP should be consistent with and informed by the demand analysis that is considered by a board of directors in a strategic planning process. For example, if a utility were to pursue a "demand" expansion strategy that the utility considered a low risk probable outcome, it would be incumbent upon the utility to include an analysis of this in their LTRP application.

The Panel will neither craft a utility's strategic plan, nor its LTRP. The role of the Panel is to determine whether an LTRP, developed by the FEU, is in the public interest. To that end, section 44.1(2)(g) provides opportunity for a panel to request information that is relevant to its analysis and deliberations respecting LTRPs. Further, in the BC Hydro Court of Appeal Decision[18] the court notes that it is generally not the role of the BCUC to manage the affairs of the utility. This Commission Panel agrees, and reiterates the distinction between the BCUC creating a strategic plan or even an LTRP versus requesting strategic information to allow the Panel to make an informed decision on the determination of whether an LTRP is in the public interest.

If the Commission Panel were to receive evidence that an LTRP was inconsistent with corporate strategy, then such evidence may be considered in evaluating the reliability of an LTRP and whether it was in the public interest. There is no evidence to suggest that the FEU's evidence respecting its LTRP is inconsistent with their overall corporate strategy. **Therefore the Commission Panel declines to specifically direct the FEU to provide information respecting strategic planning or strategic marketing processes.**

2.3 Should the FEU increase its focus on building long-term NGT load?

CEC inquired whether the Commission should take an active role in directing the FEU to increase its focus on building NGT load. Specifically, CEC states in its Final Argument:

> It is abundantly clear that a high volume [NGT] scenario plus will have by far the most favourable outcome on delivery rates. … The CEC is concerned that there is insufficient attention addressed in ensuring that this outcome prevails, and too much attention devoted to undirected planning for any possibility that might occur. … The CEC recommends that the Commission require FEU to develop and provide a long term strategy that focuses on achieving the goals of high volume and high NGT.[19]

[17] *Utilities Commission Act,* R.S.B.C. 1996, Chapter 473, s. 44.1(2)(g).
[18] FEU Reply Argument, p. 13.
[19] CEC Final Argument, pp. 23–24.

The FEU state in the Application that they will continue to be vigilant for additional opportunities to develop new natural gas service initiatives that add value for customers and include in their Action Plan "Continue to monitor and analyse the energy planning environment" and to "continue to implement the Companies' NGT initiative."[20] However, in response to CEC's specific recommendations regarding NGT, the FEU state that the Commission does not have jurisdiction to make such a determination.[21]

Commission determination

Providing FEU with specific direction to develop and provide a long-term strategy that focuses on achieving the goals of high volume and high NGT falls into the area of corporate strategy. **The Panel acknowledges the FEU's submissions in this regard and declines to make specific recommendations to the FEU regarding their NGT strategy.** However, the Panel is generally supportive of efforts by the FEU to place downward pressure on rates while supporting BC's Energy Objectives.

2.4 Should the FEU co-ordinate with BC Hydro in developing its resource plan?

CEC submits it would be useful for the FEU to work cooperatively with other utilities such as BC Hydro to develop coordinated long-term resource planning, and recommends that the Commission request the FEU to undertake such planning in conjunction with BC Hydro.[22]

The FEU state in their Reply Argument "FEU do not consider it appropriate to develop a joint or 'coordinated' resource plan with BC Hydro. The resource planning requirements of a vertically integrated electric utility and a natural gas transmission and delivery utility are very different … the Commission does not have jurisdiction to direct this kind of coordination."[23]

Commission determination

As previously discussed, the Commission Panel agrees with the FEU that the resource planning requirements of a vertically integrated electric utility and a natural gas transmission and distribution utility are very different. **Accordingly, the Panel does not require that, in the next LTRP, the FEU develop coordinated long-term resource planning with other utilities.** Again, the Panel notes that the RP Guidelines provide for an LTRP process that supports the specific circumstances of a utility.

2.5 Evaluating adequacy of the Application

As previously outlined in the legislative framework, in addition to compliance with other sections of the UCA, the FEU's application for a Long Term Resource Plan must meet the following criteria:

- **Adequacy**: The Panel must not accept a resource plan without meeting the minimum requirements as listed in section 44.1(2) of the UCA.

[20] Exhibit B-1, pp. 157, 164.
[21] FEU Reply Argument, p. 13.
[22] CEC Final Argument, p. 5.
[23] FEU Reply Argument, p. 15.

- **Public Interest**: A resource plan must meet the test of being in the public interest, as provided in section 44.1(6).
- **RP Guidelines**: While these are guidelines only, they are written in the context of applicable legislation, regulation and policy.
- **Previous LTRP Directives**: the FEU 2010 LTRP provided directives to the FEU respecting their current Application.

While providing directions to the FEU for their next resource plan, the Commission, from the FEU 2010 LTRP, discussed adequacy and quality of a long-term resource plan, viewing them as two separate issues. Adequacy refers to compliance with the minimum elements of a resource plan, in accordance with section 44.1(2). Adequacy is an objective measure that suggests all of the basic elements have been filed. Quality of the resource plan is a measure that requires the discretion of the Commission, and is exercised within the legislative framework that allows discretion, such as the public interests aspects of section 44.1(6) of the UCA.

Acceptance of the LTRP requires, among other things, the element of adequacy, a Commission determination that the LTRP is in the public interest, and that the LTRP addresses the directives of the previous LTRP order.

Commission panels may address the quality of the LTRP, if there is an issue. In the FEU 2010 LTRP Decision, the Commission addressed the issue of the quality of the plan. While the Commission had accepted the 2010 LTRP, and determined that the FEU 2010 LTRP was "just adequate," there were specific directives that the panel issued to guide the FEU in their current LTRP which would move the plan beyond adequate. These directives are provided, attached as Appendix B. Specifically the previous panel directed that the following must be included in the 2014 LTRP:

1. A 20-year vision for the FEU that includes business lines, customers, expectations for supply and demand, and expected major business challenges. The previous panel was quite specific, and included "an outline of what initiatives are currently planned or being considered and the status," as well as "the key drivers impacting the need and timing for human, physical and other (information technology, capital, etc.) resource requirements."[24]
2. An analysis of GHG targets with specific goals, and greater co-ordination between EEC planning and the development of future resource plans.[25]
3. An analysis of the FEU's new energy and business environment, the impact on demand, and how resource plans will reflect future demand growth. The Commission notes that the applicant described the new end-use forecasting methodology and provided a Reference Case demand forecast. However, while directed under the previous application, FEU did not provide "a detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios."[26]

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[24] FEU 2010 LTRP Decision, p. 24.
[25] Ibid.
[26] Ibid., p. 25.

In the current Application, it should be noted that: BCOAPO did not specifically address whether the resource plan should be accepted; CEC recommends that the Commission accept the plan with additional considerations and recommendations;[27] and BCSEA, with the exception of issues respecting GHG emissions reduction, supported acceptance of the plan.[28] This would imply that the interveners were not opposed to finding the LTRP adequate under section 44.1(2) of the UCA.

The FEU, in Final Argument, provided that "the LTRP complies with all legislative requirements, is in the public interest, and should be accepted."[29]

Commission determination

An LTRP must be both adequate and in the public interest. **The Commission Panel determines that this 2014 LTRP meets the minimum requirements of section 44.1(2) of the UCA and is therefore adequate.** The Commission Panel will address acceptance of the plan at the end of this Decision. The FEU complied with the minimum requirements of section 44.1(2) of the UCA, which is mandatory – the Commission Panel cannot accept an LTRP that does not meet these minimum requirements, rendering the plan inadequate. Specifically, the FEU provided a plan of demand-side measures, an estimate of the demand for energy net of DSM, a description of the facilities it intends to construct (if any), information regarding energy purchases, and a description of why further DSM measures are not planned in order to reduce demand further.

However, in order for an LTRP to be *accepted* by the Panel, the plan must also meet section 44.1(8) of the UCA, ensuring that the plan is in the public interest. While it is possible that the Panel or other stakeholders may disagree with individual assumptions and may prefer an alternative action plan, the test is whether the plan as filed meets the public interest. Issues regarding the public interest will be dealt with below, and must be considered in order to accept the plan, as adequacy is not sufficient for acceptance. Like the Panel before us, we have directives respecting the quality of the plan. These will be addressed in the remainder of the decision. In addition the Commission Panel, in this Application, will provide its comments on the quality of the filing.

It is important to note that the Commission Panel's lack of comment on any specific initiative provided in the LTRP does not imply the Panel's consent to that initiative. In particular, projects anticipated by the FEU must be evaluated with due process, such as a Certificate of Public Convenience and Necessity (CPCN) application. Acceptance of the 2014 LTRP does not constitute approval of any of the programs or initiatives addressed within the plan.

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[27] CEC Final Argument, pp. 25–26.

[28] BCSEA Final Argument, p. 8.

[29] FEU Final Argument, p. 1.

3.0 DEMAND FORECASTS

The FEU forecast demand in two different ways: annual demand (total gas volumes for the year) and peak demand (highest daily and/or highest hourly throughput that might occur during the year). Both the annual demand forecasts and the peak demand forecasts serve as input to gas supply planning. System capacity planning, however, relies primarily on the peak demand forecasts.[30]

The FEU present two sets of annual demand forecasts prepared using two different forecasting methods: the method used traditionally in past LTRP filings (the Traditional Method); and a new end-use method (the End-Use Method), introduced in the 2010 LTRP. The FEU outlines in the Action Plan, their intent to discontinue using the Traditional Method in future LTRP filings. The FEU also points out that the method used to forecast peak demand is separate and distinct from both of the two methods used to prepare the annual demand forecasts.[31]

The FEU state that they “prepared a Reference Case demand forecast using the traditional approach, and a separate Reference Case forecast using the new end-use approach. This new end-use approach also allowed the FEU to develop alternative annual demand forecasts based on a broader range of potential future scenarios that could be expected to unfold.”[32]

High and low peak demand sensitivities are presented as bandwidths surrounding the peak demand base case. The FEU state that these alternative demand levels can have an impact on the timing of need for new facilities that are required to meet growing system capacity requirements at the regional level.[33]

As previously noted, whereas the Commission Panel accepts the LTRP as adequate from a statutory compliance perspective, we have identified concerns regarding the quality of the material presented. The following discussion addresses these concerns as they pertain to the demand forecast, under three broad headings.

1. Quality of the annual demand forecast.
2. Quality of the peak demand forecast.
3. Quality of the integration between the two forecasts.

3.1 Quality of the Annual Demand Forecast

A review of the annual demand forecast gives rise to the following issues:

1. The FEU’s new End-Use Method;
2. Treatment of new customer additions; and
3. The use of a Reference Case versus a most likely scenario.

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[30] Exhibit B-1, p. 38.
[31] Ibid., p. 62.
[32] Ibid., p. 43.
[33] Ibid, p. 72

3.1.1 The End-Use Method

In their 2010 LTRP filing, the FEU state they were “investigating supplementing the traditional demand forecast with new forecasting methods [end-use].”[34]

In the current LTRP, the FEU state that they believe the End-Use Method to be a significant improvement over the Traditional Method, and intend to discontinue use of the Traditional Method and rely solely on the End-Use Method in future LTRP filings.[35]

The FEU stated that a key advantage of the End-Use Method is its ability to adequately consider changes in end-use energy demand caused by changes in technology and end-use consumption by customers.[36]

The FEU note additional advantages of their End-Use Method in final argument.

The End-Use Method is based on the CPR model, which has been successfully used at multiple client sites including the FEU for several years.[37] Repurposing an already credible model adds to the credibility of the model, and avoids the costs of building a new model from scratch.

The accuracy of the End-Use Method is enhanced by the ability to model different scenarios.[38]

The FEU submitted that providing details of assumptions, annual forecast analysis, and further development of updated forecasts require considerable time, consulting costs in the range of $75,000 to $100,000 per update.[39]

A comparison of forecast vs. actual data from the 2008 and 2010 LTRPs showed that the Traditional Method has been able to accurately predict demand for at least five years into the future.[40] Along similar lines, when asked if the FEU believe that the Traditional Method is sufficiently inaccurate that it should no longer be relied upon, they responded, “the FEU are unable to confirm that the traditional method is an inaccurate predictor of long term consumption.”[41]

The FEU were asked to compare its approach, along with the approach of other utilities, to a taxonomy of modelling techniques.[42] Demand forecasting techniques fall into two general categories: top-down and bottom-up. Bottom-up techniques can be further broken down into: bottom-up statistical and bottom-up engineering.

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[34] 2010 LTRP, TUS Reply Submission, p. 3.
[35] Exhibit B-1, p. 164.
[36] Exhibit B-2, BCUC IR 1.21.1, p. 83.
[37] FEU Final Argument, p. 24.
[38] Ibid.
[39] Exhibit B-2, BCUC IR 1.19.4, p. 59; IR 2.13.1, p. 34; IR 1.20.2, p. 80.
[40] Ibid., BCUC IR 1.21.8, p. 94.
[41] Exhibit B-5, IR 1.42.1, p. 103.
[42] L.G. Swan, V.I. Ugursal, Modeling of end-use energy consumption in the residential sector.

The FEU described their Traditional Method as a top-down approach and their End-Use Method as a bottom-up engineering approach.

The information provided on other utilities identified that:

- four utilities including the FEU use a top-down approach;
- five other utilities use a bottom-up statistical approach; and
- the FEU is the only utility using a bottom-up engineering approach.[43]

The BCSEA supports the FEU's intention to discontinue use of the Traditional Method.[44] However, they qualify their support by also observing that the End-Use Method is not particularly transparent.[45]

BCOAPO does not explicitly endorse or oppose continued use of the End-Use Method, but makes the following points: the FEU's End-Use Method is difficult to understand; while it provides additional information, this information comes at a high cost; the method is a repurposing of a model more generally used for conservation potential review; and it is difficult to know whether the new method provides any improved forecast accuracy.[46]

CEC supports end-use forecasting,[47] but also observes that "the end-use planning approach is overly complex, of inadequate use and the information is buried within the directional indicators to the extent that it cannot be properly examined by interveners and the Commission."[48]

Commission determination

The FEU intend to discontinue using the Traditional Method for demand forecasting in future LTRP filings, instead relying singularly on its End-Use Method. This is a significant departure from the 2010 LTRP filing in which it said it was "*investigating <u>supplementing</u> the traditional demand forecast with <u>new forecasting methods.</u>"*[49] 'Supplementing' is distinctly different from 'replacing'.

This gives rise to the following questions.

- Does introduction of end-use modelling provide a significant improvement over the Traditional Method for LTRP purposes?
- If so, is the specific End-Use Method adopted by the FEU the best alternative to capitalize on that improvement potential?
- If so, should the FEU discontinue the use of the Traditional Method altogether, or should it utilize the two approaches in tandem until the merits of the End-Use Method have been solidly established?

[43] Exhibit B-9, BCUC IR 2.9–2.12 and 2.14.1, pp. 25, 28, 31, 32 and 37–40.
[44] BCSEA Final Argument, p. 2.
[45] Ibid., p. 6.
[46] BCOAPO Final Argument, pp. 2–3.
[47] CEC Final Argument, p. 11.
[48] Ibid., pp. 23–24.
[49] FEU 2010 LTRP, Reply Submission, p. 3. Emphasis added.

The Commission Panel is persuaded that an end-use model may potentially provide additional insights in developing and understanding demand forecasts in the face of a number of expected and/or potential changes in technology and customer behaviour. Furthermore, the interveners generally support the continued use of end-use forecasting. However, the Panel questions the necessity of a more expensive and elaborate planning tool for the annual demand forecast, when it is the peak demand forecast that is the primary driver for infrastructure planning. A sophisticated annual demand forecasting tool would be required by an integrated utility, or a distribution utility with 10 to 20 year contracting commitments, but neither of these circumstances apply to the FEU.

The Commission Panel also agrees with the interveners that there are shortcomings in the FEU's End-Use Method as presented thus far.

- The End-Use Method lacks the ability to be replicated, and is challenging in terms of understanding its development and the results achieved.
- No evidence has been presented to substantiate the premise that a tool built for CPR analysis is the best tool for demand forecasting.
- The model has not been tested with historical data, and improved accuracy compared with the Traditional Method has not been established.
- The costs of developing updated/new forecasts with the End-Use Method compare unfavourably with the Traditional Method. And while not in evidence, the Commission Panel questions whether there are additional costs associated with the general upkeep and maintenance of such a complex and large model.
- Furthermore, the need to produce five-year benchmark rather than annual forecasts gives rise to another concern regarding cost and maintainability. The information presented on end-use methods in use by other utilities suggests that these data intensity problems are unique to the FEU's End-Use Method as opposed to an inherent limitation of end-use methods in general.

Therefore, the Commission Panel directs the FEU, to:

- **in its next LTRP filing, provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods; and**
- **continue use of the Traditional Method as a parallel approach until such time as the Commission approves a new end-use method as a substitute.**

3.1.2 New customer additions

3.1.2.1 Residential/Commercial

The FEU state that the "forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for British Columbia, while commercial customer additions are forecast based on recent trends in growth for the commercial customer group."[50] Inspection of the tables in Appendix B-1 show that the customer additions forecast remains unchanged across all five demand scenarios (Reference Case, and the four alternative scenarios) for all rate classes.[51]

The FEU provide the following explanation for holding the number of accounts constant under the strong economic growth scenarios: "According to our review of the literature, housing starts are more likely to be a leading indicator of economic growth than the reverse. Population growth is the main driver for home construction, and the changes in floor space in schools, retail, health care and other sectors also tend to follow, resulting in economic growth."[52]

The FEU also believe that "the key factor important for growing and maintaining commercial customer load will be related to the economy (i.e. a stronger economy will in general support a growing commercial sector)."[53]

Commission discussion

Regardless of whether housing starts are a leading, coincident or lagging indicator of economic growth, strong economic growth and higher housing starts are correlated (as are weak economic growth and lower housing starts). Similarly, periods of sustained strong economic growth are correlated with higher levels of new business formation. The Commission Panel therefore expects that future LTRP filings will show forecast variability in new customer additions for all scenarios based on different economic growth assumptions.

3.1.2.2 Industrial – excluding LNG

The FEU explicitly segregates new Liquefied Natural Gas (LNG) demand (presented in section 3.3.9 of the LTRP) from non-LNG industrial demand (presented in sections of 3.3.3–3.3.5 of the LTRP).

In presenting their Reference Case for non-LNG industrial demand, the FEU state: "Though interest from potential new industrial customers in acquiring gas service has increased recently, at the time the long-term forecast was prepared, there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no growth or decline in industrial customers has been forecasted."[54] Additionally, the numbers of industrial accounts also remain unchanged across scenarios.

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[50] Exhibit B-1, p. 40.
[51] Ibid., Appendix B-1.
[52] Exhibit B-2, BCUC IR 1.40.1, p. 145.
[53] Exhibit B-5, CEC IR 1.35.1, p. 88.
[54] Exhibit B-1, p. 42.

When asked to provide more information on the industrial potential, the FEU stated they could not provide additional information, citing customer confidentiality.[55] Further, they stated that industrial customers "are not forecasted using average use rates, and without specific knowledge of a new industrial customer it is not reasonable to apply an average consumption to determine a demand forecast."[56]

Commission discussion

The Commission Panel acknowledges the issues raised by the FEU in terms of incorporating new industrial customers into the forecast: confidentiality, uncertainty due to no firm commitments, and the uniqueness of each new customer that makes it difficult to use an 'average use per customer' approach. However, the Panel is not persuaded that these are insurmountable obstacles to providing an industrial forecast for the following reasons:

- Confidential components of discussions between the FEU and potential customers need not be divulged. That does not preclude a more general quantification of possibilities;
- As to lack of certainty, the very nature of forecasting is dealing with uncertainty. Particularly with long-term forecasts, the goal is not precision but rather direction and order of magnitude; and
- The End-Use Method may not provide the ideal tool for incorporating these 'lumpy' additions to demand, but that does not preclude adding in this demand through other processes, just so long as the explanation is clear and transparent.

Accordingly, the Commission Panel encourages the FEU, in the next LTRP, to provide a more complete analysis and justification of the new customer additions forecasted in the Reference Case. Furthermore, for all scenarios based on different economic growth assumptions, the forecasts for new customer additions should reflect those changed assumptions.

3.1.2.3 Industrial – LNG

The FEU state that the current low gas price environment has created new interest in using natural gas and the potential for new sources of industrial demand. One example project (Woodfibre) is presented, which could potentially increase demand on the system by 86,000 TJ per year.[57]

The FEU stated that they believe "there is a fair likelihood of the addition of a large new industrial load such as that of Woodfibre over the next decade."[58] In argument, they note that developments such as PEC/Woodfibre, Tilbury expansion, and additional customers seeking transmission service for LNG could exceed the annual existing throughput on the FEU system.[59]

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[55] Exhibit B-5, CEC IR 1 34.2, p. 87.
[56] Ibid., CEC IR 1.34.1, p. 84.
[57] LTRP, section 3.3.9, p. 61.
[58] Exhibit B-5, CEC IR 1.57.1, p. 141.
[59] FEU Final Argument, p. 20.

CEC comments that "The FEU devote limited attention to the Industrial forecast which is based only on firm commitments … Appropriate attention should be devoted to seeking out and acquiring better information with regard to potential industrial demand."[60]

BCOAPO submits in reference to the FEU's lack of a forecast of demand for the potential LNG customers that "[w]hile it may be probable that one or more of these projects may have zero demand, it does not seem reasonable to assume there will be zero demand from the entire suite of potential demands."[61]

Commission discussion

The Commission Panel notes that just one Industrial-LNG addition such as Woodfibre could represent a step-wise increase in excess of 40 percent over the Reference Case, and a second project could represent a doubling of demand over current levels.

While accepting the uncertainty involved in developing new markets and the need, in some cases, to keep business information confidential, the Panel believes that future treatments of Industrial-LNG demand would benefit from additional discussion and analysis of possible outcomes.

The Commission Panel encourages the FEU in their next LTRP filing to provide a more complete and fulsome analysis of the potential for new Industrial LNG demand over the entire forecast horizon.

3.1.3 Reference Case versus a most likely scenario

In its 2010 decision on the FEU's LTRP, the Commission instructed the FEU to present "a most likely or Reference Case demand forecast" in the next LTRP.

The RP Guidelines provide two pieces of specific guidance relating to assigning probabilities to scenarios. Guideline No. 2, pertaining to treatment of demand forecasts, states that probabilities or qualitative statements may be used to indicate that one scenario is considered more likely than others. Guideline No. 7 discusses the development of an action plan, states that the action should articulate the next steps that need to be initiated over the next four years in order to meet the most likely gross demand forecast.

Within this context, the FEU present five scenarios based on the End-Use Method: a Reference Case; and four alternative scenarios built on the base of the Reference Case.[62]

The FEU refrain from designating the Reference Case as a most likely scenario or to applying probabilities to any of the scenarios, arguing that the imprecision inherent in long-term forecasting makes any one or other of the scenarios equally likely.

[60] CEC Final Argument, p. 6.
[61] BCOAPO Final Argument, p. 3.
[62] LTRP, section 3.3.4, pp. 47–48.

Commission determination

The FEU comply with the 2010 Decision by providing a Reference Case scenario. While the FEU do not identify this scenario as the most likely, they do use it as the starting point for developing divergent scenarios and making comparisons amongst them. From the Commission Panel's perspective, the FEU are implicitly using the Reference Case as the foundation for their analysis and discussion, notwithstanding their reluctance to assign probabilities.

In acknowledging CEC's point of view, the Commission Panel sees the divergent positions as a legitimate difference of opinion rather than a matter of right versus wrong (in either direction).

The Commission Panel is satisfied that the FEU's approach of presenting a Reference Case and scenarios, without assigning probabilities, is acceptable.

However, for greater clarity in future LTRP filings, if the FEU chooses to continue their practice of not designating the Reference Case as most likely, it is incumbent upon the FEU to build their Action Plan on the basis of the Reference Case and provide explicit confirmation that they have done so.

3.2 Quality of the peak demand forecast

The FEU state that "[t]he peak demand forecast is a critical input into the FEU's activity of securing an adequate supply of natural gas and ensuring that the system infrastructure is capable of delivering natural gas where and when needed".[63] Given the critical role of the peak demand forecast, in the Panel's view, the quality of the peak demand forecast is at least as important, and perhaps of greater importance, to the quality of the LTRP than is the quality of the annual demand forecasts.

The Commission Panel identified two aspects of quality relating to the peak demand forecast presented that could be improved upon in future LTRP filings:

- Clarity of presentation; and
- Completeness of the analysis.

3.2.1 Clarity of presentation

An important aspect of the LTRP filing process is the opportunity for interveners and the Commission to review the plan. That argues for clarity of presentation in order to facilitate understanding of the FEU's material and to promote useful dialogue/inquiry.

The peak demand forecast is first introduced in chapter 3 of the LTRP, providing Core customer peak day demand for the FEU as a whole and broken out by regions: FEI, FEVI and FEW. The bulk of the peak forecast is presented in chapter 5, along with a discussion of system resource needs arising therefrom.

[63] Exhibit B-1, p. 62.

In contrast to the treatment of the annual demand forecast that is presented as a unified and uninterrupted story in chapter 3, the peak demand forecast presented in chapter 5 is more difficult to follow and understand.

Clarity issues identified by the Commission Panel include the following:

- Discussion moves from aggregate regions (e.g. FEI) to sub-regions (e.g. Coquitlam area) and back again, often lacking in clear description of how/why these changes in focus are made.
- In a similar vein, region and sub-region nomenclature is not always consistent with other sections of the LTRP, making it difficult at times to follow the presentation. By way of example, chapter 3 breaks out regional demand by FEVI, FEI and FEW, whereas the discussion in chapter 5 uses FEVI, Coastal Transmission System and Interior Transmission System.
- Data are presented at times as peak day demand and at other times as peak hour demand, often lacking a clear description of how/why these changes in focus are made.
- Discussion of demand within a region/sub-region is often interrupted by a shift to discussing possible infrastructure responses to the demand data presented thus far, even though total demand for the region/sub-region has not yet been fully presented.
- When infrastructure issues are interwoven with the demand discussion, the conclusions presented sometimes appear to be inconsistent. For example, the discussion of the Coastal Transmission System begins with a statement that the Nichol to Coquitlam pipeline is identified as a capacity constraint.[64] As various components of total peak demand are set out in the ensuing discussion, different conclusions are stated regarding when demand might bump up against capacity: the first prediction is that under the base case, capacity is hit in 2027;[65] subsequently, with additional components of the total forecast added, the prediction is that capacity will not be hit at all during the forecast horizon under the base case, and under the high scenario only in 2032.[66] Later on in the chapter, however, twinning the Nichol to Coquitlam section is characterized as needed within the next five to ten years (i.e. prior to 2025) because “the current pipeline capacity is inadequate.”[67]

Commission discussion

The information in the application regarding peak demand is not laid out in a straight-forward manner.

The Commission Panel recognizes that discussion of specific capacity issues may require specific disaggregation of the overall peak demand forecast into situation specific information. However, that does not preclude the need for a single, integrated presentation of the overall peak demand forecast as a starting point.

The Commission Panel therefore encourages the FEU, in future LTRP filings, to provide an integrated treatment of its peak demand forecasts as a foundation for further discussion of capacity responses.

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[64] LTRP, chapter 5, p. 107.
[65] Ibid., p. 108.
[66] Ibid., p. 112.
[67] Ibid., p. 128.

3.2.2 Completeness of the analysis

Section 3.1.2.3 of this document set out the Commission Panel's findings regarding the treatment of potential new Industrial-LNG customers in the context of the annual demand forecasts. For brevity, the summary of evidence will not be repeated here, but will be relied upon where/as relevant as a basis for the following discussion of the Commission Panel's findings.

New Industrial-LNG demand could potentially represent a doubling of total system throughput. However, the FEU's treatment of this issue is limited to one paragraph in the application (chapter 5, page 113). In particular, the last two sentences of that paragraph state "As no commitments have been made for any significant industrial load additions on the CTS, detailed analysis on timing and capacity requirements has not been carried out. However, the FEU will consider the overall effect of potential capacity increases, in conjunction with sustainment needs, when planning the infrastructure requirements on the CTS."

Commission discussion

The Commission Panel encourages the FEU in their next LTRP filing to provide a more complete and fulsome analysis of the potential for new Industrial LNG peak demand and the impacts on peak demand levels over the forecast horizon.

3.3 Quality of the integration between the two forecasts

As noted, the FEU present two distinct treatments of demand: annual demand and peak demand.

Annual demand forecasts are developed primarily using the End-Use Method, and scenarios are developed by changing input assumptions to the model. Peak demand forecasts are developed by determining the relationship between consumption and cold weather by customer class and grossing up these values by customer counts.[68] High and low scenarios are developed by adjusting the Core customer peak demand by a percentage factor. Depending on which page of the LTRP is referenced, the percentage factors used to produce the high and low forecasts are 125 percent and 79 percent respectively[69] or 126 percent and 76 percent.[70]

The FEU state that because two distinct approaches are used to generate annual demand forecasts and peak demand forecasts, "at this time, it is not possible to directly relate forecast annual consumption to peak demand."[71]

[68] Exhibit B-1, p. 63.
[69] Ibid., p. 109.
[70] Ibid.
[71] Exhibit B-5, CEC IR 1.72.1, p. 172.

Commission discussion

The Commission Panel accepts that the use of two different methods makes explicit reconciliation of the forecasts difficult. However, the Commission Panel considers this a computational limitation of the forecast methods used as opposed to a good reason for not providing some form of reconciliation.

The Commission Panel has identified the following areas where there are opportunities to establish stronger linkages between the two forecasts for readers of the LTRP:

- the number of customers, by class;
- how new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand; and
- how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions.

The Commission Panel is not suggesting that a rigorous numerical reconciliation should be performed to marry the two sets of forecasts. Rather, we are suggesting that the FEU could improve its explanation by demonstrating the apparent linkages, assumptions, and consistencies more effectively.

4.0 COST EFFECTIVE DEMAND SIDE MEASURES

4.1 DSM Legislative requirements

Once an estimate of the demand for natural gas in the FEU's territory is developed, the next step in the resource planning process (section 44.1(2)(b) of the UCA) is to determine how the FEU intend to reduce the demand for energy by taking demand-side measures (DSM).[72] The FEU is also required under section 44.1(2)(f) of the UCA to provide an explanation of why they are not planning to use DSM to replace facilities the FEU intend to construct and energy purchases the FEU intend to make.

In addition, in the FEU 2010 LTRP Decision, the FEU were directed under section 44.1(2)(g) of the UCA to include in the next LTRP:

- Greater coordination between DSM planning and the development of future resource plans. This will allow for a more detailed presentation of future DSM programs over a longer time period with expected impacts to be included as part of the LTRP process.
- Development of a limited number of scenarios detailing the impacts of varying degrees of DSM planning measures on the demand forecast and GHG emission reductions.

Section 44.1(8)(a) and (c) of the UCA also require that, in determining whether the FEU's LTRP is in the public interest, the Commission must consider BC's energy objectives and whether the FEU intend to pursue adequate, cost effective demand-side measures. Adequacy, for the purpose of this section of the UCA, is defined in the

[72] The FEU refer to DSM as Energy Efficiency and Conservation.

DSM regulations as including programs specifically designed for low-income households, rental accommodations, and schools including post-secondary institutions. The DSM regulations also specify how the cost-effectiveness of the portfolio or measures is determined.

4.2 The FEU LTRP DSM Proposal

The FEU have recently received approval for approximately $35 million in DSM funding for each year from 2014–2018 as part of the FEI 2014–2018 Performance Base Ratemaking (PBR) Application (PBR Application). In that decision (PBR Decision), the Commission determined that the FEU's proposed DSM funding for 2014–2018 pass portfolio level cost effectiveness tests and are not unreasonable.[73]

Summary results of the FEU's DSM funding approvals received for 2014–2018 are included in Table 1 and Table 2 below.

Table 1 – The FEU's 2014–2018 DSM Expenditure Schedule

	Actual Expenditures ($000s)	Approved Expenditures ($000s)	Requested Expenditures ($000s)				
Program Area	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	11,295	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	603	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	4,865	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	358	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	394	1,502	1,207	1,218	1,233	1,218	1,210
CEO	2,200	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities	4045*	n/a	4,515	5,015	4,420	4,425	4,365
Totals	19,715	35,574	34,353	36,537	35,839	35,388	35,874

* The value for Enabling Activities for 2012 is in fact for Portfolio-level activity [74]

Table 2 – The FEU 2014–2018 Portfolio Level DSM Cost Effectiveness Results

Program Area and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios			
	2014	2015	2016	2017	2018		TRC	Portfolio*	Utility	Participant
ALL PROGRAMS										
FEI	637,255	1,255,547	1,733,589	2,265,196	2,787,418	21,247,479	0.94	1.36	1.32	2.15
FEVI	66,693	136,195	204,155	270,295	336,344	2,798,187	1.04	1.31	1.39	3.74
Total	703,948	1,391,743	1,937,743	2,535,491	3,123,762	24,045,666	0.95	1.35	1.33	2.33

* Includes the MTRC adder for programs that require it (i.e. TRC/MTRC hybrid) [75]

[73] FEI 2014–2018 PBR Decision, p. 277.

[74] Ibid., p. 251.

[75] FEI 2014–2018 PBR Decision, p. 276.

In the PBR Decision, the Commission supported a focus on effectiveness of the management of the DSM portfolio, including ensuring that the most effective programs are pursued and an appropriate balance pursued in terms of different customers' ability to access DSM programs.[76] The PBR Decision also included the following determinations:

- Adequacy and Cost-Effectiveness: The PBR Panel determined that the FEU's DSM proposal is adequate and cost-effective (within the meaning of the DSM regulations), with the exception of not having a DSM program intended specifically for rental accommodation. The FEU were directed to, by the end of 2015, file with the Commission one or more DSM programs intended specifically for rental accommodation.[77]
- Setting the DSM Funding Envelope: The PBR Panel determined that DSM rate impacts are a relevant consideration when considering the interests of persons in BC who receive or may receive service from the FEU, however the focus should be on mitigating rate impacts for non-participants and not on maintaining the competitive position of natural gas. The PBR Panel considered that reducing the level of cost-effective DSM in order to maintain the competitive position of gas may be contrary to BC's energy objectives, specifically objectives in support of emission reductions.[78]

  The PBR Panel further determined that the FEU should not use the Commission's FEU 2012–2013 DSM approval as a guide to the upper level of rate impacts that are appropriate for the programs the FEU are proposing. The 2012–2013 DSM funding level was primarily set based on practical considerations related to how much cost effective DSM the FEU could realistically achieve.[79]

  In approving the FEU's request for a five-year expenditure period, the PBR Panel noted that the next CPR is expected by 2016, and at that time, the FEU will be free to file a new DSM application if circumstances warrant.[80]
- Evaluation, Measurement and Verification (EM&V): The PBR Panel determined that the FEU's approach to EM&V sufficiently protects ratepayers' interests and is therefore acceptable at this time.[81]

For the purpose of the 2014 LTRP, the FEU assume that current DSM funding levels of approximately $35 million annually (in 2014 dollars, excluding inflation) for all service regions continues over the planning horizon. The FEU state that they plan to conduct a new CPR starting in 2015 to provide new conservation potential data for natural gas in BC with which to design DSM programs beyond 2018. Based on the next CPR results, the FEU state they will develop a DSM program plan and funding application to be implemented post-2018.[82]

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[76] FEI 2014–2018 PBR Decision, p. 260.
[77] Ibid., pp. 274, 275.
[78] Ibid., p. 261.
[79] Ibid., p. 262.
[80] Ibid., p. 275.
[81] Ibid., p. 281.
[82] Exhibit B-1, pp. 75, 89.

The FEU further submit that, under the Reference Case, DSM programs will lead to reductions in greenhouse gas emissions of 82,000 tonnes of carbon dioxide equivalent (tCO_2e) in 2016; 212,000 tCO_2e in 2021; and 672,000 tCO_2e in 2033.[83]

Interveners were supportive of the FEU's Action Plan over the next four years to carry out the DSM Plan included in the PBR Application. However, concerns were raised with regard to the adequacy of longer-term DSM information and analysis included in the FEU's LTRP.[84]

An issue raised during the proceeding was what information should be included to meet the requirements of section 44.1(2)(f) to provide an explanation as to why DSM is not increased above planned levels to replace: (i) planned gas purchases; or (ii) planned infrastructure investments, including how BC's energy objectives should be considered. These two issues are addressed in subsequent sub-sections of this decision.

Commission determination

Ideally, the utility should first file an LTRP and then file a DSM expenditure schedule under section 44.2 of the UCA. This allows the utility to receive guidance regarding the overall size and approach of the DSM funding proposal prior to filing the detailed DSM expenditure schedule. This preferred order of filing is reflected in the UCA – the Commission is required for DSM expenditure filings to consider the most recent long-term resource plan filed by the utility in determining whether to accept the DSM expenditure schedule, and not vice versa.

However, in this situation, the LTRP was filed after DSM expenditure schedule was filed. In the PBR Application, the FEU received approval under section 44.2 of the UCA for a five-year DSM expenditure schedule covering 2014–2018 Any benefit that would be expected from this LTRP in providing guidance to a subsequent DSM expenditure filing application is therefore substantially reduced.

As a result this decision is focused on providing guidance on DSM related information that should be included in the next LTRP to inform a subsequent DSM expenditure schedule filing. **Consistent with the PBR Decision, the Commission Panel accepts the FEU's DSM 2014–2018 plan as being in the public interest.**

4.3 Planned energy purchases

The RP Guidelines set out an approach that should be followed to justify proposed DSM funding level. Specifically, the RP Guidelines[85] require the development of alternative resource portfolios, with each portfolio consisting of a different combination of supply and DSM resources. These alternative portfolios would then be evaluated against the utility's stated resource planning objectives and a preferred resource portfolio selected.

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[83] Exhibit B-1, p. 156.

[84] CEC Final Argument, pp. 17–19; BCSEA Final Argument, pp. 2, 3, 7; BCOAPO Final Argument, p. 4.

[85] RP Guidelines, p. 4.

The FEU 2010 LTRP Decision also provided direction regarding DSM scenario analysis. Specifically, the Commission directed the FEU to develop a limited number of scenarios detailing the impacts of varying degrees of DSM planning measures on the demand forecast and GHG emission reductions.[86]

However, the FEU submit that a portfolio level analysis of DSM options would not be appropriate as the FEU do not own gas reserves and file for approval of an Annual Contracting Plan for gas purchases, and so do not have a range of energy generation portfolios against which to compare alternative demand side portfolios.[87]

CEC supports the FEU's position, agreeing that this LTRP is fundamentally different than in the case with BC Hydro, but submits that DSM scenarios would be relevant to long-term resource planning. CEC recommends that the Commission request the FEU to develop scenarios for DSM based on funding.[88]

BCSEA and BCOAPO agree that the FEU's use of an annual DSM spending level of $35 million for the LTRP is appropriate in the context of a long-term resource plan. BCSEA considers that the crucial element is that the DSM Plan component of the LTRP calls for acquiring all cost-effective conservation and efficiency energy savings and that the amount of DSM spending required to achieve that objective is more appropriately addressed in a DSM expenditure schedule proceeding.[89]

Commission determination

The FEU are required to include, in the LTRP, information regarding the energy purchases that the FEU intend to make in order to serve its estimated demand. Section 44.1(2)(f) then requires that the FEU include an explanation as to why these purchases are not planned to be replaced by demand side measures.[90]

However, as previously discussed, the Panel agrees with the FEU that they are not a traditional vertically integrated utility in the sense that they do not supply the gas commodity to all customers in their service territory. Therefore it would not be appropriate in the FEU's case to try to undertake a direct comparison of the FEU's DSM spending, to its own gas costs.

The Panel considers that a different approach is required to explain why the FEU planned gas purchases are not replaced by DSM. The Panel will consider whether compliance within the broader requirements of BC's energy objectives[91] could also address the narrower requirements of section 44.1(2)(f) in the FEU's case.

With respect to BC's energy objectives, the Panel specifically notes the objective to take demand-side measures and to conserve energy. In addition, the BC Energy Plan states "... the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management

[86] Commission Order G-14-11, p. 24.
[87] Exhibit B-2, BCUC IR 1.2.1, p. 2; FEU Final Argument, pp. 18, 19.
[88] CEC Final Argument, p. 19.
[89] BCSEA Final Argument, p. 7; BCOAPO Final Argument, p. 4.
[90] UCA, section 44.1(2)(e).
[91] BC's Energy Objectives, section 44.1(8)(a).

programs."[92] The DSM Regulations do not differentiate between customers based on who supplies the gas (the FEU or a third party) in determining the adequacy and cost effectiveness of the EEC portfolio.

The Panel therefore considers that in order for the Commission to evaluate the FEU's LTRP against BC's energy objectives, the FEU LTRP should include a broader analysis of the BC costs and benefits of different levels of DSM funding. The Panel is satisfied that, given that the FEU is not a traditional vertically integrated utility, this information should also satisfy the requirements of section 44.1(2)(f) as it relates to the FEU's own planned energy purchases and the DSM scenario analysis related requirements from the 2010 LTRP Decision.[93]

The Panel therefore directs the FEU to include, in its next LTRP, the following information:

- **The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;**
- **Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:**
  - **Total Resource Cost/modified Total Resource Cost test results;**
  - **Utility Cost Test result, expressed as a ratio and $/GJ;**
  - **Delivery rate impact;**
  - **Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers; and**
  - **Estimated gas (GJ) and GHG emission reductions.**

The issue of how to best coordinate the timing of the next LTRP with future DSM expenditure schedule filings is addressed in section 5 of this decision.

4.4 Planned infrastructure Investments

The FEU provide an explanation as to why recommendations for system capacity related resources outlined in Chapter 5 of the LTRP are not replaced by demand-side measures. They state "the effect of EEC and shifting end-use trends on peak demand cannot be predicted without knowing the specific details of equipment installations. Thus, it is reasonable to assume that EEC and changing end-use trends offset one another."[94]

CEC submits that, although the FEU have provided the essentials of the DSM requirements, the DSM plan should also address the likelihood and potential of DSM to moderate peak energy demand and therefore delay or avoid the need for new infrastructure. CEC raised a concern that the only DSM option the FEU identified to reliably reduce peak demand is curtailment of interruptible customers and submits that advanced metering infrastructure (AMI) for natural gas could also be an important option in reducing peak demand. CEC

[92] BC Energy Plan, p. 5.
[93] UCA, section 44.1(2)(g).
[94] Exhibit B-1, p. 99.

recommends that the Commission direct the FEU to address the potential for introducing AMI as part of its long range planning.[95]

BCOAPO submits that the FEU should attempt to develop cost effective DSM programs or offerings to incent a shift in use to off-peak consumption in order to avoid system infrastructure costs related to higher capacity needs.[96]

Commission determination

The Commission Panel agrees with the interveners that future filings would benefit from additional analysis focused on identifying potential DSM strategies that could favourably affect peak demand. **Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments**.

5.0 FACILITIES TO MEET THE EXPECTED DEMAND

Section 44.1(2)(d) of the UCA requires that the FEU include in their LTRP a description of the facilities that the FEU intend to construct or extend in order to serve an estimate of the demand that the FEU expects after they have taken cost-effective demand-side measures.

The RP Guidelines state that feasible resources, both committed and potential, should be listed. These resources are defined in the RP Guidelines as investments or actions by the utility to decrease, shift or increase energy and/or capacity supply or demand.[97] The RP Guidelines further state that the utility should establish an action plan, which outlines "the detailed acquisition steps for those resources … which need to be initiated over the next four years in order to meet the most likely gross demand forecast."[98] The action plan should include a contingency plan that specifies how the utility would respond to changed circumstances such as changes in loads, market conditions or technology and resource options.[99]

In addition, in the FEU 2010 LTRP Decision, the FEU was directed under section 44.1(2)(g) of the UCA to include in the next LTRP a description of the impacts of each demand forecasting scenario on future resource requirements with consideration of the variables which could further affect these scenarios.

The RP Guidelines state that feasible resources, both committed and potential, should be listed and measured against the objectives established by the utility. This includes identifying utility and customer costs (life cycle costs, impact on rates, etc.), associated risks and lost opportunities. The RP Guidelines also state that the utility

[95] CEC Final Argument, pp. 17, 18.
[96] BCOAPO Final Argument, p. 4.
[97] RP Guidelines, p. 4.
[98] Ibid., p. 5.
[99] Ibid., p. 5.

should establish a four-year action plan and a contingency plan that specifies how the utility would respond to changed circumstances.[100]

The FEU state in their LTRP that sustaining the FEU's existing natural gas system infrastructure and planning to meet future demand growth are undertaken to ensure that planned improvements optimize operation of the system as a whole.[101]

The FEU submit that with annual increases in forecast peak demand and potential new source of demand from NGT and industrial sources, the FEVI Transmission System, FEI Coastal Transmission System (CTS) and FEI Interior Transmission System (ITS), transmission systems will all face capacity constraints within the 20-year planning period. The FEU submit that system reinforcements are needed in the Lower Mainland portion of FEI's natural gas delivery system to address long-term requirements for both system sustainment and capacity constraints and system constraints related to capacity requirements in the Okanagan region of the FEI's ITS, are also expected in the immediate term.[102]

Panel consideration of the FEU's facilities component of the LTRP will be split between: (i) the items contained in the FEU's System Resource Action Plan for system capacity and system sustainment; and (ii) completeness of the FEU's System Resource Plan.

5.1 The FEU's Action Plan for system resources

The FEU propose the following Action Plan items:

1. <u>Plan for and prepare CPCN applications for near-term system requirements identified in the FEU Five-Year Capital Plans.</u> The Application outlines projects for which the FEU intend to submit CPCN applications to the Commission in the near term. These high priority projects are located on the Lower Mainland (LM) Intermediate Pressure (IP) System and the Coastal System (CS) and are the:

    - Coquitlam IP pipeline replacement (LM);
    - Nichol to Port Mann Transmission Pipeline (TP) loop (LM);
    - Cape Horn to Coquitlam TP pipeline loop (CS);
    - Fraser IP pipeline replacement (LM); and
    - Nichol to Roebuck TP pipeline loop (CS).[103]

    The FEU state that their planning efforts are undertaken to ensure that planned improvements optimize operation of the system as a whole, and so these system upgrade requirements have been integrated with the reinforcement options that are under consideration to meet the FEU's capacity needs. The FEU

[100] Ibid., pp. 4, 5.
[101] Exhibit B-1, p. 131.
[102] Ibid.
[103] Ibid., p. 165.

also state that they will conduct further inspection and analysis on pipelines in the Burns Bog area before determining an appropriate course of action for this project.[104]

2. Expand the Tilbury LNG facility. The FEU state they will work toward implementing an expansion of the Tilbury LNG facility in accordance with the BC Government's Special Direction No. 5.[105] Construction planning and the LNG facility expansion are expected to be in place by 2016.[106]

3. Continue monitoring and evaluating system expansion needs in the Okanagan area. The FEU state they have identified a constraint in the Okanagan region of the ITS as early as 2017, and will continue to evaluate the three proposed reinforcement options presented in the LTRP. In addition, the FEU state they will continue to monitor FBC's Integrated System Plan and potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods. The FEU state that, should FortisBC Inc. proceed with a gas-fired peaking generating station, this or any other large additional industrial load will result in a need to submit a CPCN for pipeline facility expansion.[107]

BCOAPO states that the discussion of system resource needs contained in the LTRP satisfies the requirements of section 44.1(2)(d), and does not take issue with the general options and preferences expressed by the FEU in the infrastructure section.[108]

CEC commented on the FEU's system resource needs and alternatives and raised no concerns. CEC recommends acceptance by the Commission of this portion of the LTRP.[109]

Commission discussion

The Commission Panel is satisfied that the Action Plan items identified to address system capacity and system sustainment needs are consistent with the demand identified in the Reference Case. However, the Panel reiterates that acceptance of the 2014 LTRP does not constitute approval of any of the programs or initiatives addressed within the plan.

The Panel notes that no contingency plan was developed as per the RP Guidelines and will address this in the subsequent section.

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[104] Exhibit B-1, p. 165.
[105] Ibid., p. ES-14.
[106] Ibid., p. 111.
[107] Ibid., p. 165.
[108] BCOAPO Final Argument, p. 5.
[109] CEC Final Argument, pp. 20–22.

5.2 Completeness of the FEU's System Resource Plan

As stated above, the LTRP should include a contingency plan that specifies how the utility would respond to changed circumstances, such as changes in loads, market conditions or technology and resource options. For resources with considerable uncertainty, the RP Guidelines state that the LTRP should incorporate an experimental design and monitoring plan to allow for hindsight evaluation of associated market impacts and full resource costs.[110]

The RP Guidelines also state "In most circumstances, Certificates of Public Convenience and Necessity ('CPCN') applications should be supported by resource plans filed pursuant to Section 45 [now section 44.1] of the UCA. The Commission expects that resource plans should help facilitate the review of utility revenue requirements and rate applications."[111]

The FEU present low and high peak day forecasts for each the three components of their transmission system: Vancouver Island (FEVI), the Coastal Transmission System (CTS) and the Interior Transmission System (ITS).

For FEVI, the FEU state that Low and High scenarios are also calculated by adjusting the Reference Case Core growth by 79 percent and 125 percent respectively. The Low and High scenarios move the FEVI capacity constraint back by three years to 2031, or advance it by four years to 2024.[112]

For CTS, they state that Low and High scenarios are calculated by adjusting the Reference Case Core growth by 76 percent and 126 percent respectively. The FEU also analyze the impact of phasing out the Burrard load from 2014 to 2016. With the inclusion of the Burrard Thermal load the Low and High cases delay the capacity constraint on the FEI CTS until 2032, or advance it forward to 2023, respectively. However, if Burrard Thermal is phased out, the FEU state that no capacity reinforcements are required in the 20-year planning window.[113]

Regarding ITS, the FEU state that "[t]he Reference Case demand scenario shows that demand on this portion of the ITS will exceed capacity in 2018, and in 2019 and 2017 for the Low and High scenarios respectively. The factors for generating the Low and High bandwidths were not provided.[114].

While these Low and High scenarios provide bandwidths around the Reference Case, they are not explicitly tied to any specific source(s) of demand variability that might explain those lower or higher peak demand outcomes.

The FEU do not provide system resource plans for the high and low demand cases.

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[110] RP Guidelines, p. 5.
[111] Ibid., p. 2.
[112] Exhibit B-1, pp. 103–104.
[113] Ibid., pp. 108–109.
[114] Ibid., p. 116.

"The CEC submits that there are significant changes underway in the marketplace which are not adequately covered in the LTRP" and that "the Commission should request a more fulsome review of the potential market transformation that may occur and its role in energy use."[115]

In this section of the decision, the Panel will discuss the completeness of the System Resource Plan based on potential market developments as described in evidence. Potential facilities that do not appear to be included in the System Resource Needs and Alternatives section of the LTRP are FEU facilities related to: (i) Potential new LNG export facilities and LNG export demand; and (ii) Renewable Natural Gas (RNG) Offering. These are discussed further below.

1. <u>LNG export demand</u>

The FEU were asked by CEC to provide a quantitative analysis of the potential effect of the addition of LNG export facilities in the Lower Mainland and Vancouver Island areas. Instead of a quantitative analysis, the FEU responded by stating that there was interest from potential customers seeking to construct LNG facilities in the Lower Mainland and Vancouver Island to attach to the FEU system, but that these opportunities and associated forecasts were not included in the LRTP because these discussions are confidential and in a development stage.[116]

a. WesPac LNG Export

On June 20, 2014, WesPac Midstream – Vancouver LLC (WPMV) submitted an application to the National Energy Board (NEB) for a 25 year license to export LNG.[117] WMPV states in the application that the LNG for export will be produced at the Tilbury LNG plant owned and operated by FEI.[118] WPMV applied for an export license volume corresponding to 400 million cubic feet per day of natural gas equivalent LNG production.[119] WPMV stated, "FEI has confirmed to WPMV that there is sufficient capacity available, or that its pipelines in existing rights-of-way can be readily expanded to ensure that there is sufficient capacity available, on its system to accommodate current and future liquefaction capacity at the Tilbury LNG Plant."[120] In response to BCUC IR 2.22.3, the FEU stated that FEI had the opportunity to review the NEB application but did not have input.[121] In response to BCUC IR 2.22.5, the FEU provided a diagram which was updated to include possible infrastructure investments required on the CTS to accommodate potential load associated with WPMV. These included:

- The possible future looping of existing NPS 42 pipeline (from Langley to Nichol and from Huntingdon to Riverside).
- Increase in lateral diameter to NPS 30 pipeline at the Tilbury LNG Plant.[122]

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[115] CEC Final Argument, p. 23.
[116] Exhibit B-5, CEC IR 1.10.8, p. 32.
[117] Exhibit A2-4.
[118] Exhibit A2-4, p. 4.
[119] Ibid.
[120] Ibid., p. 5.
[121] Exhibit B-9, BCUC IR 2.22.3, p. 57.
[122] Ibid., BCUC IR 2.22.5, p. 59.

b. Northwest Territories Energy Corporation and Yukon Energy Corporation

The Northwest Territories (NWT) Action Plan dated December 2013 outlines the intent of the Government of Northwest Territories to further explore developing a supply chain of LNG in communities across Inuvik after commissioning a pilot project aimed at powering the needs of Inuvik with LNG.[123] FEI currently has a RS 16 contract with the NWT Energy Corporation to supply the Inuvik power generation pilot project however this expires at the end of 2014. The NWT Energy Corporation will be required to execute a RS 46 contract to continue receiving LNG supply from FEI.[124] NWT Energy is targeting a LNG load for power generation at Inuvik which approximates to 250,000 GJ/year.[125] In response to BCUC IR 1.29.2.2 FEU stated that the potential Inuvik demand was not included in the Application due to:

- Uncertainty regarding future commitments considering NWT Energy Corporation currently takes LNG from the FEI on a spot basis; and
- By extrapolating the purchases from NWT Energy Corporation from January 2014 to April 2014 the FEU estimate a 48,000 GJ/year demand for 2014, which is materially lower than the 250,000 GJ/year forecast.[126]

c. Yukon Energy Corporation

The Yukon Energy Corporation (YEC) has applied to the Yukon Utilities Board for approval of the 2015 replacement of two diesel-generating units with up to three modular natural gas fired generating units.[127] YEC states that they will secure LNG supply from Tilbury until a cheaper source of LNG is available. YEC stated that FortisBC has met with them and confirmed that there is ample LNG at Tilbury to meet their needs and that they are coordinating with NT Energy in order to transport the LNG to the north.[128] When questioned, the FEU stated that YEC and the FEU were currently negotiating a firm contract under RS 46, but that since there was no executed agreement that they have omitted this from the demand forecast.[129] The FEU reiterate that they "do not forecast industrial demand until it has a firm commitment from the customer."[130]

d. Woodfibre LNG

It was stated in the Application that FEVI and Pacific Energy Corporation (PEC) have entered into a development agreement where FEVI would perform development work required to expand FEVI's system to provide firm natural gas transportation service to the proposed LNG export facility at Woodfibre. FEVI would be responsible for feasibility studies, engineering and the obtaining of regulatory and other relevant approvals.[131] The FEU

[123] Exhibit B-2, BCUC IR 1.29.0, pp. 123–124.
[124] Ibid., BCUC IR 1.29.1, p. 124.
[125] Ibid., BCUC IR 1.29.0, p. 123–124.
[126] Ibid., BCUC IR 1.29.2.2, p. 125.
[127] Exhibit B-2, BCUC IR 1.29.0, p. 123.
[128] Ibid., BCUC IR 1.30.0, pp. 126–127.
[129] Ibid., BCUC IR 1.30.1, p. 127.
[130] Ibid., BCUC IR 1.30.2, p. 127.
[131] Exhibit B-1, p. 106.

included a graph showing the potential impact of the Woodfibre project on the FEU Total Annual Energy Demand forecast.[132] When discussing system resource needs the FEU stated that "FEVI would need to reinforce its existing system with pipeline looping and add compression on the system to meet PEC's natural gas transportation service requirement; this infrastructure expansion would exactly match the firm transportation capacity contracted by PEC."[133] In response to BCUC 1.32.1, the FEU stated that "large increases in base load (such as the Woodfibre example) would tend to increase overall peak demand on a given system. Should these large base load increases occur, then it may be necessary to advance planned reinforcements, supplement planned reinforcements or install new infrastructure."[134] The 2014 LTRP notes the target in-service date for the PEC Woodfibre LNG export facility is April 2018, assuming a PEC decision to proceed is made by December 2015.[135]

2. <u>Renewable Natural Gas Offering – Biomethane Upgrader Facility</u>

Appendix A-7 provides an in-depth analysis of FEI's Renewable Natural Gas Offering. The analysis outlines that while the biogas producer typically owns upgrading equipment, there are certain circumstances where FEI must control the upgrading process and associated facilities. The FEI states that a CPCN would be filed should these circumstances arise, however the FEI expects that this will be relatively infrequent and will likely only occur where the supplier is a regional or municipal government.[136] The Commission Panel for the Biomethane Service Offering proceeding determined that FEI or its regulated affiliate may own and operate an upgrader when dealing with regional or municipal governments.[137]

Commission determination

The Panel accepts the FEU's System Resource Plan as it adequately addresses the Reference Case.

The Commission Panel has previously discussed the fact that the FEU have not provided any specific alternative demand scenarios, or any contingency plans that might respond to changed demand circumstances. Although FEU discuss the impact of high and low peak day demand scenarios in their separate discussions of the FEVI, FEI Coastal and FEI Interior systems, they do not provide specific system resource plans for these alternative scenarios.

The System Resource Plan should include all resources that are will be required for CPCNs that are expected to be filed within the four-year period of the Action Plan. The RP Guidelines suggest that a contingency plan(s) is appropriate. **To ensure regulatory efficiency in the review of CPCN applications, the Panel directs that the FEU include in their next LTRP, a contingency plan(s) that outlines the impact(s) to FEU's System Resource Needs and Alternatives based on potential changes in supply, demand, market conditions and significant new developments in the industry that were not identified in the LTRP as being associated with the Reference Case**

[132] Ibid., p. 62.
[133] Exhibit B-1, p. 106.
[134] Exhibit B-2, BCUC IR 1.32.1, p. 130.
[135] Exhibit B-1, p. 106.
[136] Exhibit B-1, Appendix A-7, p. 5.
[137] FEI 2012 Biomethane Decision, p. 100.

or most-likely forecast. The contingency plan(s), at a minimum, should provide for the low and high alternate peak day demand scenarios.

6.0 ENERGY PURCHASES

Section 44.1(2)(c) of the UCA requires that the FEU include in their LTRP an estimate of the demand for energy that it expects to serve after they have taken cost-effective demand-side measures and section 44.1(2)(e) requires that the LTRP include information regarding the energy purchases from other persons that the FEU intend to make in order to serve that demand.

In the FEU 2010 LTRP Decision, the FEU were directed by the Commission to include in the next LTRP a description of the impacts of each demand forecast scenario on future resource requirements with consideration of the variables which could further affect each of these scenarios.

The RP Guidelines also provide additional guidance regarding energy purchase information that should be included in an LTRP. The RP Guidelines state that feasible resources, both committed and potential, should be listed and measured against the objectives established by the utility, and that the FEU should establish an action plan covering the next four years.[138]

The FEU submit that they design their energy portfolios to provide secure and reliable daily gas supply to customers so that both forecasted normal and peak design day demand is met. Supply resources include contracted term and spot supply, gas injected and withdrawn from various leased storage facilities, and company owned on-system LNG facilities. Over the short term, the FEU state that the portfolios do not change significantly from year to year but can change over the long run as market changes occur and new infrastructure is developed.[139]

The FEU state that although the forecast normal and peak demand profiles have not changed significantly over the last several years, this could change in the future as a result of low gas prices and industrial growth requiring a change to the mix of resources in the portfolio. In addition, the FEU compete for resources within the region and the availability of the current resources in the portfolio may change due to regional infrastructure developments related to LNG exports and increased demand from Alberta for supply from northeastern BC.[140] The FEU have identified a potential constraint in the Kingsvale to Yahk pipeline and state that removing this physical constraint could provide its customers with increased long-term diversity and security of supply as well as increase the opportunity for the FEU to provide expanded transportation services to facilitate increased access to markets for growing natural gas production.[141]

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[138] RP Guidelines, pp. 4, 5.
[139] Exhibit B-1, p. 134.
[140] Ibid., p. 135.
[141] Exhibit B-1, pp. 137–138.

Due to regional and North American gas market developments, the FEU submit that it must continue to be proactive in securing reliable and diversified gas supply cost-effectively over the long-term.[142] In order to meet these objectives, the FEU state in their Action Plan that it will use the following broad strategies to secure future resources:

- Manage volatility in natural gas prices by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms.
- Continue to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to ensure that the marketplace in BC offers supply liquidity and competitive pricing compared to neighbouring regional markets.
- Continue to establish key relationships with major producers that plan to develop gas supply in the Horn River, Montney and other producing regions of BC over the long-term, including those actively involved in attempting to develop LNG exports to Asian markets.
- Evaluate opportunities within the FEU's own operating region to improve infrastructure that will provide greater access to markets, leading to better diversity and reliability within the gas portfolio over the long-term.[143]

In addition, the FEU state that, to protect customers from market price volatility and help ensure the competitiveness of natural gas rates, the FEU will explore opportunities for longer term price risk management strategies that may include using fixed price purchases, investing in natural gas reserves and financial hedging.[144]

The FEU include in the LTRP a description of the impact of DSM on annual natural gas demand, however these demand forecast scenarios do not have a significant impact on the FEU's gas supply planning.[145] The FEU submit that, as its gas Annual Contracting Plan (ACP) is shorter term in nature and updated annually, the impact of demand-side measures on demand forecast scenarios is inherently considered in the ACP.[146]

Energy purchase related issues raised during this preceding were (i) whether the FEU's price risk management principles and objectives have been adequately addressed in the LTRP; (ii) longer term gas price risk management strategies; and (iii) investment in natural gas reserves. These issues are addressed below.

6.1 Price risk management principles and objectives

Price risk management includes the use of both physical and financial tools and strategies to reduce market price volatility and provide some rate stability for customers. The FEU state that they are not seeking approval of the FEU's gas supply portfolio or the Companies' price risk management plans which are approved through

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[142] Ibid., p. 139.
[143] Exhibit B-1, p. 166.
[144] Ibid., p. 166.
[145] Ibid., pp. 84, 85.
[146] Ibid., p. 132.

separate applications and information on the companies' ACP and Price Risk Management Plans (PRMPs) is included for context.[147]

The FEU state that the Price Risk Management Review Report is the appropriate forum to review price risk management principles and objectives and that this is consistent with past practice. They further state that "[t]he next Long Term Resource Plan may be an appropriate forum to discuss, at a high level, price risk management strategies or outcomes resulting from the Price Risk Management Review, which are long term in nature and which impact long term resource planning decisions, such as long term supply contracting or investing in reserves."[148]

CEC states: "FEU devote several pages to Price Risk Management in the LTRP. CEC recognizes that the topics are covered in detail in the [Annual Contracting Plan] and the [Price Risk Management Plans]."[149]

Commission determination

To promote regulatory efficiency, resource planning should start with a long-term focus and then cascade down to shorter forecast intervals and be used to inform future filings. Specifically, the LTRP should describe the FEU's long-term vision for price risk management and provide broad principles, which can then be used to inform the PRMP. The PRMP is then in turn used to inform the FEU's ACP, which is used to determine the FEU's energy contracts that are executed and filed under section 71 of the UCA.

The Commission Panel considers that the LTRP should inform the PRMP on price risk management principles, and not vice versa. The UCA requires that, when considering utility filing of energy supply contracts under section 71 of the UCA, the Commission must consider the most recent LTRP filed by the utility. **The Panel therefore directs the FEU to include in the next LTRP a description of its long-term vision for price risk management and provides broad principles, which can be used to inform the PRMP.**

6.2 Longer term gas price risk management strategies

The FEU state in the LTRP that to protect customers from market price volatility and help ensure the competitiveness of natural gas rates, the FEU will explore opportunities for longer term price risk management strategies that may include using fixed price purchases, investing in natural gas reserves and financial hedging.[150]

On July 12, 2011 the Commission rejected the FEU's 2011-2014 PRMP, with the exception of the Sumas/AECO Basis Swaps. Specifically, the Commission rejected the FEU's proposed hedging strategy because:

(i) the FEU's PRMP objective of maintaining the competitiveness of natural gas with other energy sources was considered inappropriate for the following reasons:

[147] Ibid., p. 132.
[148] Exhibit B-9, BCUC IR 2.28.1, p. 74.
[149] CEC Final Argument, p. 22.
[150] Exhibit B-1, p. 166.

- Issues related to business risk have complexities beyond those of natural gas commodity cost and are more appropriately dealt with in the context of a ROE Hearing.
- In the long run, the demand for gas vs electricity will not be driven by a PRMP but will be driven by market forces.
- In the current market environment, short run competitiveness with electricity is seen to be largely driven by events of limited duration that cause market volatility, making this objective indistinguishable from the moderating of price volatility objective.
- Promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate; and

(ii) while moderating the volatility of natural gas prices was considered a reasonable goal for the FEU to pursue, the Commission did not consider that the FEU's proposed PRMP was the most cost effective approach or solution. However, the Commission also stated that it has no desire to "close the door" on the consideration of all future hedging options and that, given a change in external conditions, the Commission "would consider proposals on behalf of ratepayers to help in mitigating the relevant risks."[151]

CEC submits that the "FEU address the issue of long-term price volatility and appear to focus on transitioning from shorter term planning to longer term planning throughout the discussion such as in longer term hedging and fixed price contracts. The CEC submits that this is an appropriate transition to make and supports the activities profiled in this regard."[152]

BCOAPO agrees with the FEU that the current low natural gas commodity prices provide an opportunity for the FEU to adopt long-term strategies to improve long-term cost certainty and stability. However, BCOAPO submits that such long-term strategies must recognize the uncertainty inherent in the natural gas market.[153]

Commission determination

Consistent with the Commission's determination in Order G-120-11, **the Commission Panel finds that (i) the FEU's objective of maintaining the competitiveness of natural gas with other energy sources is inappropriate and should not be included in a future PRMP, and (ii) while the Panel has no desire to close the door on the consideration of all future hedging options, the PRMP must show that this is the most cost effective approach or solution to moderating the volatility of natural gas prices or reducing risks related to price disconnects.**

The Panel also notes that acceptance of the 2014 LTRP does not constitute approval of any of the programs or initiatives addressed within the plan.

[151] Order G-120-11, Appendix A, pp. 21, 22, 25.
[152] CEC Final Argument, p. 23.
[153] BCOAPO Final Argument, p. 6.

6.3 Investment in natural gas reserves

The FEU state that "[w]hile the focus of price risk management in the past has been primarily on short term planning, the FEU believe the current market price environment creates opportunities for longer term strategies. Going forward, these could include consideration of longer term instruments or tools [such as fixed price purchases or investment in natural gas reserves] that could improve long term cost certainty and help provide stability in rates, but they also ensure security of supply for customers."[154]

The parties explored the issue of investment in natural gas reserves during the proceeding. In its Final Argument the FEU summarized its position, stating that "depending on how future infrastructure is developed, the FEU may not be able to access gas supply, or may have reduced access to supply, at fair market prices and/or face price disconnects during periods of high demand." In its view, investments in natural gas reserves in part can help ensure there are long term commitments to move natural gas to Station 2 or other access points where the FEU hold firm transportation capacity to move the gas to its service areas. However, it submits, "issues and concerns regarding the possibility of purchasing reserves are best dealt with through the Price Risk Management Review Report."[155]

BCPSO is "somewhat alarmed by FEU's (hypothetical) investment in natural gas reserves as it appears FEU would consider this an investment in rate base entitling it to an allowed return on investment to be included in rates. Investment in gas reserves is a relatively high risk activity, which does not appear to be compatible with the relatively low risk nature of natural gas delivery."[156]

CEC supports what it characterizes as the FEU's transition from short-term planning to long-term planning. CEC specifically supports the FEU activities supporting the transition and states that investment in natural gas reserves should be "fully investigated and prioritized for review."[157]

BCSEA agree that this should be deferred to a future proceeding stating it is "very wary of the policy and financial risks of FEU investing in gas reserves to the account of ratepayers." In its view, there is no evidentiary record in the current proceeding on which the Panel could reasonably support the FEU pursuing investment in gas reserves.[158]

Commission discussion

The Panel takes no position on the issue of the FEU investing in natural gas reserves. We agree with BCSEA that the evidentiary record in this proceeding is insufficient to make any such determination, and that this issue is best addressed in a future proceeding. Further, we note that the FEU are not requesting a determination on this issue.

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[154] Exhibit B-1, p. 133.
[155] FEU Final Argument, pp. 27–28.
[156] BCPSO Final Argument, p. 5.
[157] CEC Final Argument, p. 23.
[158] BCSEA Final Argument, p. 7.

7.0 BC'S ENERGY OBJECTIVES

Section 44.1(8)(a) of the UCA also require that, in determining whether the FEU's LTRP is in the public interest, the Commission must consider BC's energy objectives. Section 2 of the CEA sets out British Columbia's energy objectives. Those most relevant to this proceeding include:

(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 emissions

(i) by 2012 … to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 … to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 … to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 … to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;

(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;

In addition, in the FEU 2010 LTRP Decision, the Commission directed the FEU to include in the next LTRP:

- An analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the company believes it can reasonably attain over time.
- An outline of the impact of the implementation of new initiatives on the demand forecast and GHG emission reductions.[159]

The FEU estimate that BC GHG reduction target will require a reduction in BC GHG of 21.4 $MtCO_2e$ for 2020.[160]

The FEU estimate that, under the reference, case GHG emissions from end-use gas consumption will increase from 10.1 $MtCO_2e$ to 10.3 $MtCO_2e$ from 2011 to 2021 (a 2 percent or 0.2 $MtCO_2e$ increase). The FEU estimate

[159] FEU 2010 LTRP Decision, p. 24.

[160] Exhibit B-1, pp. 155, 156.

that under scenario C the GHG increase over the same period would be 0.5 $MtCO_2e$, and scenario B shows a decrease in GHG of 0.3 $MtCO_2e$.[161]

The FEU also estimate that, under the Reference Case, DSM will contribute 0.2 $MtCO_2e$ in 2021 towards the BC emission reduction target and NGT can contribute 0.1 $MtCO_2e$, for a combined GHG reduction estimate of 0.3 $MtCO_2e$. The FEU estimate that this combined GHG reduction will be 0.25 $MtCO_2e$ under scenario B and 0.2 $MtCO_2e$ under scenario C.[162]

The FEU also estimate that selling the biomethane from all currently approved RNG projects could account for GHG reductions of 0.02 $MtCO_2e$ by 2020 and that the Switch 'N Shrink program could account for GHG reductions of 0.03 $MtCO_2e$ over the next eight years to 2020.[163]

The FEU submit that "FEU's [2010 LTRP] position to act on social and environmental priorities has not fundamentally changed" and that a consideration of BC's energy objectives supports the acceptance of the LTRP.[164]

In addition, the FEU's 2014 Action Plan includes the following items:

- Continue to Implement the Companies NGT initiatives: the FEU will continue to implement the Companies' NGT initiatives … while also capturing an opportunity to assist in reducing the GHG emissions of B.C.'s transport sector.
- Pursue approval of EEC funding for the 2014-2018 period.[165]

Commission determination

The Commission Panel finds that the FEU's proposed LTRP is generally consistent with British Columbia's energy objectives. In making this determination, the Panel considered the follow issues raised during this proceeding: (i) the FEU contribution to BC GHG reduction targets; and (ii) the FEU statements regarding BC benefit from the use of gas rather than electricity for heating applications in BC. These issues are discussed below.

7.1 Reducing GHG emissions

BCSEA submits that the FEU 2014 LTRP plan is deficient in its failure to include an analysis of GHG emissions. BCSEA asks the Commission to either reject that portion of the plan or alternatively, to direct that the FEU include, in its next long-term resource plan, a comprehensive forecast and analysis of GHG emissions due to

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[161] Ibid., p. 71.
[162] Ibid., p. 156.
[163] Ibid., p. 155.
[164] Exhibit B-2, BCUC IR 1.6.1; FEU Final Argument, p. 10.
[165] Exhibit B-1, p. 164.

industrial demand and a reasonable estimate of the FEU's portion of the GHG emissions reductions necessary to meet BC's legislated GHG targets.[166]

BCSEA submits that, while the regulatory regime does not (yet) assign to the FEU a specific quantity of GHG reductions, the purpose of the plan is to articulate a long-term vision that goes beyond the minimum, status quo regulatory requirements.[167] The FEU counter that the legislature has not assigned a GHG reduction target responsibility to the FEU at this time.[168] The FEU further state "Since FEU do not own or control the appliances that the Utilities' customers use for space and water heating, FEU consider that the end-use customer is responsible for the emissions generated from using natural gas for space and water heating. This would seem to be the BC Government's position as well, since the carbon tax is charged to the end-use customer."[169]

BCSEA also submits that the FEU has not complied with the requirements of the 2010 LTRP Decision to "provide a comprehensive forecast of combined GHG emissions reductions, nor does it provide an analysis of net GHG emissions reductions (or increases) taking into account increased load."[170] The FEU question whether 'net GHG emission reductions' were contemplated in 2010, and submit that it is not clear what this analysis would entail.[171]

Commission determination

The Panel determines that the FEU provided sufficient information in the LTRP to meet the 2010 LTRP requirements to provide: (i) an analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time; and (ii) an outline of the impact of the implementation of new initiatives on the demand forecast and GHG emission reductions. The Panel directs the FEU to also provide this GHG related information in the next LTRP.

The Commission Panel agrees with the FEU that it has been assigned no specific GHG reduction targets to meet. Further, the Panel considers that the government, rather than the Commission, is a more appropriate arbiter of the issue of whether the FEU's contribution to BC GHG reduction targets is sufficient.

7.2 Promotion of gas for BC heat/hot water

The FEU submit that "using the Government's rationale that natural gas can be used to reduce global GHG emissions, the Companies believe the efficient use of natural gas for heating applications in B.C. can provide a similar benefit."[172]

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[166] BCSEA Final Argument, p. 1.
[167] Ibid., p. 4.
[168] FEU Reply Argument, p. 25.
[169] Exhibit B-2, BCUC IR 1.7.2, p. 22–23.
[170] BCSEA Final Argument, p. 5.
[171] FEU Reply Argument, p. 25.
[172] Exhibit B-1, p. 30.

The Commission stated in Order G-120-11 Reasons for Decision "... the Commission Panel bases its finding that the objective related to competitiveness of natural gas with other energy sources (principally electricity) is inappropriate for the following reasons: promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate"[173]

However, the FEU believe that the reference to the Panel's statement made in Order G-120-11 Reasons for Decision is made out of context since the regulation cited in the Panel's statement has since been amended. They further state that "improving the competitive position of gas for BC space and water heating relative to other fuel sources should be supported where it can be demonstrated that a shift towards natural gas for BC space/water heating is in the public interest."[174]

The FEU further submit that:

> there are many instances where improving the competitiveness of natural gas could be in the public interest. Using the Government's rationale that natural gas can be used to reduce global GHG emissions, the FEU believe the efficient use of natural gas for heating applications in BC can provide a similar benefit for global emissions when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions, or reduces the need to import electricity from neighbouring jurisdictions. Such a use would be in the 'public interest' in the sense that GHG emissions do not respect jurisdictional borders and it is therefore in the interest of British Columbians to reduce global emissions. Similarly, ensuring that natural gas service is available in those areas not currently served by natural gas could also be in the public interest as it provides customers with energy choice, can reduce emissions (if the alternate fuel is oil), and can reduce heating costs (if the alternate fuel is tier two electricity).[175]

However, the FEU's Action Plan does not incorporate any activities to promote the use of natural gas for heating applications.

BCSEA asked the Commission to reject the FEU's argument in the 2014 LTRP that "the use of natural gas for heating applications in B.C. can provide a ... benefit for global [GHG] emissions," submitting:

> With respect, there is no persuasive evidence that displacing electricity use in B.C. would actually increase the export of clean B.C. electricity. Nor is there persuasive evidence that if displaced electricity was exported it would necessarily reduce GHG emissions outside B.C. by an amount greater than the increase in GHG emissions within B.C. due to the increase combustion of natural gas. …

[173] Order G-120-11 Reasons for Decision, p. 21.
[174] Exhibit B-9, BCUC IR 2.2.1, p. 7–9.
[175] Ibid., BCUC IR 2.2.1, pp. 7–9.

> It is noted that in Order and Decision G-120-11 concerning FEU's corporate predecessors' application for approval of a price risk management plan, the Commission Panel rejected the Companies' proposed stated objective to promote the competitiveness of natural gas over other energy sources, principally electricity. Among other reasons, the Panel determined that "promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate.[176]

In their reply argument, the FEU note that the statement referred to by BCSEA is in the "Planning Environment" section, stating "FEU recognize that not every intervener necessarily agrees with the statement, but that does not mean that it needs to be 'determined' as BCSEA-SCBC recommends. The FEU submit that the Commission does not need to decide anything with respect to this issue."[177]

Commission discussion

The Commission Panel notes that, while the FEU's opinion is that the use of natural gas for heating applications in BC can provide a GHG benefit, the FEU have not put forward proposed actions in the LTRP that require a determination of whether this opinion is reasonable or not. As a result, the Commission Panel agrees with the FEU that no determination is required on this issue and will consider it no further.

8.0 THE INTERESTS OF CUSTOMERS

In determining whether to accept a long-term resource plan, the Commission must consider "the interests of persons in British Columbia who receive or may receive service from the public utility."[178] An issue raised during this proceeding was whether the FEU's NGT demand from customers within British Columbia could possibly be displaced by LNG export demand if significant LNG export demand materializes.

The FEU submit that the LTRP is in the interests of person in British Columbia who receive or may receive service from the public utility.[179] Regarding BC NGT demand, the FEU confirm that Rate Schedule (RS) 46, the rate schedule under which the FEU supplies LNG, is first come, first serve regardless of end use.[180] The FEU forecast RS 46 volumes based on forecast NGT demand based on the vehicle incentives it anticipates, and states that under the Greenhouse Gas Reductions (Clean Energy) Regulation (GGRR), customers who take advantage of the incentives are required to buy their natural gas delivered through the FEU system.[181]

The FEU state that, given competing requests for service, priority would be given to a customer with a longer-term agreement and if two competing customers had similar contract term length, priority would be given to

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[176] BCSEA Final Argument, pp. 3–4.
[177] FEU Final Argument, p. 23.
[178] UCA, section 44.1(8)(d).
[179] FEU Final Argument, p. 15.
[180] Exhibit B-2, BCUC IR 1.37.2, pp. 140–141.
[181] Ibid., BCUC IR 1.25.2, p. 113.

the one with the higher demand volume.[182] The FEU also confirm no priority is given to parties who received vehicle incentives and state "It is not the intent of FEU to distinguish between domestic and export customers and it is not the intent of FEU to change Rate Schedule 46 to give effect to these requirements. Further, under NAFTA, the FEU could not give priority to domestic customers over US customers."[183]

Commission determination

The Commission Panel accepts the FEU's 2014 LTRP as being in the interests of persons in British Columbia in compliance with section 44.1(8)(d) of the UCA.

The evidence suggests that although all the RS 46 LNG demand forecast customers in the LTRP is for NGT, and these customers must contract for their supply from the FEU, there is a potential for future non-NGT export customers to get priority over NGT customers in British Columbia if they are prepared to sign a contract. In the event that there is insufficient capacity to provide for both domestic and export demand the issue of whether the "first come first served" provisions of RS 46 is consistent with the "interests of persons in BC" provisions of s. 41.1(8)(d) of the UCA may arise. However, non-NGT RS 46 demand is not included in the forecast presented in this LTRP.

If, in the next LTRP, the FEU provide a demand forecast that includes the possibility of there being insufficient supply for both NGT BC customers and non-BC LNG export customers, then the Panel directs the FEU to address how it will insure compliance with section 44.1(8)(d) of the UCA. One factor that could be addressed in considering of the possibly competing demands is a strong LNG export business impacts the interests of British Columbian's who receive service (as a whole). The FEU have stated that all ratepayers will potentially benefit from increased throughput in the system attributable to LNG export. The FEU should address how the interests of all ratepayers are balanced against the interests of NGT customers specifically.

9.0 TIMING OF THE NEXT LTRP

One of the purposes of an LTRP is to support regulatory efficiency and inform other Commission processes, as well as play a role in the planning processes within a utility's own business. Ideally, an LTRP will: introduce opportunities that may lead to future projects that require CPCN applications; provide context for applications for approval of DSM expenditures; and provide an overview to support Annual Contracting Plans and Energy Supply Contracts.

The Panel's objective is to set a date for the next LTRP that supports regulatory efficiency and effectiveness and considers LTRP objectives.

The FEU previously filed an LTRP in 2010, 2008 and 2006 (2 year gap, 2 year gap, 4 year gap respectively).

[182] Ibid., BCUC IR 1.37.2, pp. 140–141.
[183] Exhibit B-9, BCUC IR 2.24.1, p. 65.

The FEU state in their Reply Argument that any directives made by the Commission Panel that makes the planning process more onerous is unreasonable, given the PBR decision's reduction to LTRP expenditures by $600,000.[184] It is duly noted that the Commission in the PBR decision suggested that the next LTRP would be in 5 years.[185]

The FEU state on page 90 of the Application: "Based on the next CPR results [the FEU plan to] conduct a revised long term [DSM] analysis for inclusion in the next LTRP."[186]

The BCSEA Final Argument supports the FEU's commitment to, based on the next CPR results, "conduct a revised long term DSM analysis for inclusion in the next LTRP."[187]

Assuming that the LTRP will include an analysis of DSM portfolio options:

- The next LTRP should come after the 2015 CPR.
- The LTRP should come before the FEU's filing for 2019 DSM expenditures (which would be expected in 2018).

The FEU state that they may request additional DSM funding earlier than 2018 if additional cost effect DSM opportunities are identified during the PBR period.[188]

From a DSM perspective, the next LTRP should be filed by either 2016 or 2017 (after the 2015 CPR but before the expected 2017 filing of the next DSM expenditure request).

From a PRMP perspective, future PRMP applications should be informed by the LTRP, and therefore the next LTRP should be filed before the current PRMP approvals expire.

CPCN applications (for LNG export not exempted from Commission review) could be received within the next two years. Potential LNG export demand has not been included in the 2014 LTRP. The FEU suggested that there is a fair degree of uncertainty around the possible LNG opportunities that may become available to the FEU.[189]

Commission Panel determination

The Commission Panel directs the FEU to file their next LTRP on or before June 30, 2017. This will provide a reasonable degree of regulatory efficiency in that there is a 3-year gap between LTRP filings. This date ensures that the 2017 LTRP will inform the DSM filing scheduled for 2018. It is scheduled after the 2015 CPR, ensuring that the FEU can incorporate the results of this updated study. This will also ensure that the date of the LTRP is scheduled to inform subsequent energy supply agreements.

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[184] FEU Reply Argument, p. 29.
[185] FEI 2014–2018 PBR Decision, p. 210.
[186] Exhibit B-1, p. 90.
[187] BCSEA Final Argument, p. 3.
[188] FEI 2014–2018 PBR Decision, pp. 276–277.
[189] Exhibit B-2, BCUC IRs 1.29.2.2, p. 125; 1.30.1, p. 127; 1.30.2, p. 127; 1.31.2, p. 129.

10.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page**
1.	**Therefore the Commission Panel declines to specifically direct the FEU to provide information respecting strategic planning or strategic marketing processes.**	8
2.	**The Panel acknowledges the FEU's submissions in this regard and declines to make specific recommendations to the FEU regarding their NGT strategy.**	9
3.	**Accordingly, the Panel does not require that, in the next LTRP, the FEU develop coordinated long term resource planning with other utilities.**	9
4.	**The Commission Panel determines that this 2014 LTRP meets the minimum requirements of section 44.1(2) of the UCA and is therefore adequate.**	11
5.	**Therefore, the Commission Panel directs the FEU, to:** • **in its next LTRP filing, provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods; and** • **continue use of the Traditional Method as a parallel approach until such time as the Commission approves a new end-use method as a substitute**	15
6.	**The Commission Panel is satisfied that the FEU's approach of presenting a Reference Case and scenarios, without assigning probabilities, is acceptable.**	19
7.	**Consistent with the PBR Decision, the Commission Panel accepts the FEU's DSM 2014–2018 plan as being in the public interest.**	25

8.	**The Panel therefore directs the FEU to include, in its next LTRP, the following information:** • **The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;** • **Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:** o **Total Resource Cost/modified Total Resource Cost test results;** o **Utility Cost Test result, expressed as a ratio and $/GJ;** o **Delivery rate impact;** o **Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers; and** o **Estimated gas (GJ) and GHG emission reductions.**	27
9.	**Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments**.	28
10.	**The Panel accepts the FEU's System Resource Plan as it adequately addresses the Reference Case.**	34
11.	**To ensure regulatory efficiency in the review of CPCN applications, the Panel directs that the FEU include in their next LTRP, a contingency plan(s) that outlines the impact(s) to FEU's System Resource Needs and Alternatives based on potential changes in supply, demand, market conditions and significant new developments in the industry that were not identified in the LTRP as being associated with the Reference Case or most-likely forecast.**	34–35
12.	**The Panel therefore directs FEU to include in the next LTRP a description of its long term vision for price risk management and provides broad principles which can be used to inform the PRMP.**	37
13.	**the Commission Panel finds that (i) the FEU's objective of maintaining the competitiveness of natural gas with other energy sources is inappropriate and should not be included in a future PRMP, and (ii) while the Panel has no desire to close the door on the consideration of all future hedging options, the PRMP must show that this is the most cost effective approach or solution to moderating the volatility of natural gas prices or reducing risks related to price disconnects.**	38
14.	**The Commission Panel finds that FEU's proposed LTRP is generally consistent with British Columbia's energy objectives.**	41

15.	**The Panel determines that the FEU provided sufficient information in the LTRP to meet the 2010 LTRP requirements to provide: (i) an analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time; and (ii) an outline of the impact of the implementation of new initiatives on the demand forecast and GHG emission reductions. The Panel directs the FEU to also provide this GHG related information in the next LTRP**.	42
16.	**The Commission Panel accepts the FEU's 2014 LTRP as being in the interests of persons in British Columbia in compliance with section 44.1(8)(d) of the UCA.**	45
17.	**If, in the next LTRP, the FEU provides a demand forecast that includes the possibility of there being insufficient supply for both NGT BC customers and non-BC LNG export customers, then the Panel directs the FEU to address how it will insure compliance with section 44.1(8)(d) of the UCA.**	45
18.	**The Commission Panel directs FEU to file their next LTRP on or before June 30, 2017.**	46

DATED at the City of Vancouver, in the Province of British Columbia, this *3rd* day of December 2014.

Original signed by:

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D. M. MORTON
PANEL CHAIR/COMMISSIONER

Original signed by:

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C. A. BROWN
COMMISSIONER

Original signed by:

____

H. G. HAROWITZ
COMMISSIONER

Original signed by:

____

I. F. MACPHAIL
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-189-14

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

an Application by FortisBC Energy Utilities
(comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc.
and FortisBC Energy (Whistler) Inc.)
for Acceptance of the 2014 Long Term Resource Plan

BEFORE: D. M. Morton, Panel Chair/Commissioner
C. A. Brown, Commissioner
H. G. Harowitz, Commissioner
I. F. MacPhail, Commissioner

December 3, 2014

O R D E R

WHEREAS:

A. On March 25, 2014, FortisBC Energy Utilities (FEU), comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., filed their 2014 Long Term Resource Plan (Application) pursuant to section 44.1 of the *Utilities Commission Act*, for acceptance by the British Columbia Utilities Commission (Commission). The FEU are not seeking approval of any particular elements identified within the plan;

B. By Order G-56-14 dated April 16, 2014, the Commission established a written hearing process and a regulatory timetable with two rounds of information requests to review the Application;

C. In this proceeding, Aitken Creek Gas Storage (Aitken Creek), British Columbia Hydro and Power Authority (BC Hydro), British Columbia Pensioners' and Seniors' Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, Counsel of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO), BC Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA), Canadian Office and Professional Employees' Union, Local 378 (COPE 378), Commercial Energy Consumers Association of British Columbia (CEC), and Just Energy (B.C.) Limited Partnership (Just Energy) registered as interveners;

…/2

D. During the course of the proceeding, two rounds of information requests were submitted to FEU, and FEU responded;

E. On August 18, 2014, FEU submitted its final argument where it sought to have the Application accepted;

F. On September 3, 2014, BCOAPO, BCSEA, and CEC submitted their final arguments;

G. On September 17, 2014, FEU submitted its reply argument; and

H. The Commission has reviewed the Application and the evidence submitted through the review process.

NOW THEREFORE for the reasons set out in the decision accompanying this order:

1. The Commission accepts the FortisBC Energy Utilities 2014 Long Term Resource Plan to be in the public interest pursuant to subsection 44.1(6) of the *Utilities Commission Act*.

2. The Commission directs the FortisBC Energy Utilities to comply with all determinations and directives as set out in the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this *3rd* day of December 2014.

BY ORDER

Original signed by:

D. M. Morton
Commissioner

Application by FortisBC Energy Utilities
(comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc.
and FortisBC Energy (Whistler) Inc.)
for Acceptance of the 2014 Long Term Resource Plan

THE REGULATORY PROCESS

ACTION	DATE (2014)
Deadline for Registration of Interveners and Interested Parties	Friday, May 16
Commission Information Request No. 1	Friday, May 23
Intervener Information Request No. 1	Friday, May 30
Filing of Participant Assistance Cost Award Budgets	Friday, June 6
FEU Responses to Information Requests No. 1	Thursday, June 19
Commission and Intervener Information Requests No. 2	Monday, July 14
FEU Responses to Information Requests No. 2	Thursday, July 31
Intervener Notice of Intention regarding filing of Intervener Evidence	Thursday, August 7
FEU Final Argument	Monday, August 18
Intervener Final Argument	Wednesday, September 3
FEU Reply Argument	Wednesday, September 17

FEU 2010 Long Term Resource Plan Decision (G-14-11)
2010 Commission Panel Directives

Pursuant to section 44.1(2) (g) of the UCA, the 2010 Commission Panel directed FEU to include the following in the next LTRP:

1. Terasen Utilities – a 20 year vision

This vision could describe what Terasen may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe.

Areas which are appropriate to be covered in preparing this vision include but are not limited to the following:

- The extent to which markets will be transformed.
- The extent to which Terasen can contribute to overall British Columbia GHG reduction objectives.
- The impact the company's contributions to GHG reduction will have on demand.
- The importance new technology and new initiatives will have on the overall business, and their significance in terms of percentage share of its traditional business.
- An outline of what initiatives are currently planned or being considered, and the status.
- The impact Terasen's efforts have, and expect to have, on meeting British Columbia's energy objectives.
- The key drivers impacting the need and timing for human, physical and other (information technology, capital etc.) resource requirements.

2. GHG reduction targets – EEC planning and impacts of New Initiatives

In respect of GHG reduction targets as impacted by EEC planning and New Initiatives the Commission Panel directs future LTRPs to include the following:

- An analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the company believes it can reasonably attain over time.
- Greater coordination between EEC planning and the development of future resource plans. This will allow for a more detailed presentation of future EEC programs over a longer time period with expected impacts to be included as part of the LTRP process.
- Development of a limited number of scenarios detailing the impacts of varying degrees of EEC planning measures on the demand forecast, and GHG emission reductions.
- An outline of the impact of the implementation of New Initiatives on the demand forecast and GHG emission reductions.

3. New business environment and approach to Demand Forecasting

Future LTRPs need to more adequately convey Terasen Utilities' understanding of the new energy and business environment, its impact on gross demand, and how resource plans will be reflective of future demand growth. Accordingly, Terasen is directed to include the following in future resource plans.

- A description of the new end-use forecasting methodology, how it compares with Terasen's traditional demand forecasting approach, and reconciliation of the results of the two different approaches.

- The development of a most likely or reference case demand forecast and outline of the underlying assumptions taking into account potential legislative, regulatory or market transformation changes.
- An integration of the reference case demand forecast with the EEC scenarios and a description of the impacts.
- A detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios.
- A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.

Finally, Terasen is directed to provide an estimate of the extent to which its proposed programs and initiatives will contribute to the achievement of British Columbia’s energy objectives.

LIST OF ACRONYMS

AMI	Advanced metering infrastructure
ACP	Annual Contracting Plan
BCSEA	B.C. Sustainable Energy Association and the Sierra Club British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre
COPE 378	Canadian Office and Professional Employees' Union, Local 378
CPCN	Certificate of Public Convenience and Necessity
CEA	*Clean Energy Act*
CS	Coastal System
CTS	Coastal Transmission System
CEC	Commercial Energy Consumers Association of British Columbia
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review
Commission or BCUC	British Columbia Utilities Commission
DSM	Demand-side management
DSM Regulation	Demand-Side Measures Regulation, BC Reg. 326/2008
EEC	Energy Efficiency and Conservation
FEI	FortisBC Energy Inc.
The FEU	FortisBC Energy Utilities, comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FEU 2010 LTRP	Terasen Utilities 2010 Long Term Resource Plan

LIST OF ACRONYMS

FEU 2014 LTRP	FEU 2014 Long Term Resource Plan
GHG	Greenhouse gas
GGRR	Greenhouse Gas Reductions (Clean Energy) Regulation
IRs	Information requests
ITS	Interior Transmission System
IP	Intermediate Pressure
LNG	Liquefied Natural Gas
LM	Lower Mainland
mTRC	modified Total Resource Cost Test
NGT	Natural gas transmission
NWT	Northwest Territories
PEC	Pacific Energy Corporation
PBR	Performance based ratemaking
PRMP	Price Risk Management Plan
Q3	Third quarter
RS	Rate Schedule
RNG	Renewable natural gas
tCO2e	Tonnes of carbon dioxide equivalent
TP	Transmission Pipeline
UCA	*Utilities Commission Act*
WPMV	WesPac Midstream – Vancouver LLC
YEC	Yukon Energy Corporation

IN THE MATTER OF
the *Utilities Commission Act*, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Utilities
2014 Long Term Resource Plan

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated April 14, 2014 – Appointment of Panel
A-2	Letter Dated April 16, 2014 – Commission Order G-56-14 establishing a Regulatory Timetable
A-3	Letter Dated May 23, 2014 – Commission Information Request No. 1 to FEU
A-4	Letter Dated July 10, 2014 – Response to BCSEA Request and Timetable
A-5	Letter Dated July 14, 2014 – Commission Information Request No. 2 to FEU
A-6	Letter Dated July 29, 2014 – Commission Response regarding BCSEA Scope Request
A-7	Letter Dated September 4, 2014 – Amendment of Panel
A2-1	Letter Dated May 23, 2014 – Commission Staff Filing 2014 Gas Outlook Northwest Gas Association
A2-2	Letter Dated May 23, 2014 – Commission Staff Filing MISO Peak Forecasting Methodology Review Whitepaper
A2-3	Letter Dated May 23, 2014 – Commission Staff Filing Rate Schedule 16 Pilot Program 2013 Annual Report
A2-4	Letter Dated July 14, 2014 – Commission Staff Filing Wespac Midstream–Vancouver LLC Application for a license to export gas

Exhibit No.	Description
APPLICANT DOCUMENTS	
B-1	**FORTISBC ENERGY UTILITIES (FEU)** Letter Dated March 25, 2014 – Long Term Resource Plan
B-1-1	Letter Dated April 3, 2014 – FEU Submitting Erratum to Figure 5-12, Page 118
B-2	Letter Dated June 19, 2014 - FEU Submitting Response to BCUC IR No.1
B-2-1	Letter Dated June 26, 2014 - FEU Submitting Response to BCUC IR 1.47.1 Erratum
B-3	Letter Dated June 19, 2014 - FEU Submitting Response to BCPSO IR No.1
B-4	Letter Dated June 19, 2014 - FEU Submitting Response to BCSEA IR No.1
B-5	Letter Dated June 19, 2014 - FEU Submitting Response to CEC IR No.1
B-6	Letter Dated June 19, 2014 - FEU Submitting Response to COPE IR No.1
B-7	Letter Dated July 14, 2014 – FEU Submitting Response on BCSEA request for scope determinations
B-8	Letter Dated July 18, 2014 – FEU Reply Submission on Scope
INTERVENER DOCUMENTS	
C1-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated April 17, 2014 – Request for Intervener Status by Christopher Weafer
C1-2	Letter dated May 30, 2014 – CEC Submitting Information Request No. 1 to FEU
C1-3	Letter dated July 14, 2014 – CEC Submitting Information Request No. 2 to FEU
C1-3	Letter dated July 16, 2014 – CEC Submitting Response to Scoping Exhibit A-4
C2-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCPSO)** Letter dated May 2, 2014 – Request for Intervener Status by Tannis Braithwaite and James Wightman
C2-2	Letter dated May 30, 2014 – BCPSO Submitting Information Request No. 1 to FEU
C2-3	Letter dated July 14, 2014 – BCPSO Submitting Information Request No. 2 to FEU
C2-4	Letter dated July 16, 2014 – BCOAPO Submitting Response to Scoping Exhibit A-4

Exhibit No.	Description
C3-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated May 5, 2014 – Request for Intervener Status by Leigha Worth and Jim Quail
C3-2	Letter dated May 30, 2014 – Cope378 Submitting Information Request No. 1 to FEU
C4-1	**JUST ENERGY (B.C.) LIMITED PARTNERSHIP.(JUST ENERGY)** Letter dated May 9, 2014 – Request for Intervener Status by Nola Ruzycki
C5-1	**AITKEN CREEK GAS STORAGE (AITKEN CREEK)** Letter dated May 15, 2014 – Request for Intervener Status by Charlie Mertz, Krista Mitchell and Ian Webb
C6-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter dated May 16, 2014 – Request for Intervener Status by Janet Fraser
C7-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB OF BRITISH COLUMBIA (BCSEA)** Letter dated May 16, 2014 – Request for Intervener Status by William J. Andrews and Thomas Hackney
C7-2	Letter dated May 30, 2014 – BCSEA Submitting Information Request No. 1 to FEU
C7-3	Letter dated July 9, 2014 – BCSEA Submitting Scoping Request
C7-4	Letter dated July 14, 2014 – BCSEA Submitting Information Request No. 2 to FEU
C7-5	Letter dated July 16, 2014 – BCSEA Submitting Response to Scoping Exhibit A-4

INTERESTED PARTY DOCUMENTS

Exhibit No.	Description
D-1	**SENTINEL ENERGY MANAGEMENT (SE)** Letter and Online Registration Dated April 17, 2014 – Request for Interested Party Status by Jim Langley
D-2	**FERUS NATURAL GAS FUELS (FERUS)** Letter dated May 12, 2014 – Request for Interested Party Status by Jason Beck