IN THE MATTER OF

FORTISBC ENERGY INC.

INQUIRY INTO THE OFFERING OF PRODUCTS AND SERVICES
IN ALTERNATIVE ENERGY SOLUTIONS
AND OTHER NEW INITIATIVES

REPORT

December 27, 2012

Before:

N.E. MacMurchy, Commissioner/Panel Chair
D.A. Cote, Commissioner
L.A. O'Hara, Commissioner
A.A. Rhodes, Commissioner

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SECTION 1 INTRODUCTION

1.1 Background

FortisBC Energy Inc. has filed several applications with the British Columbia Utilities Commission (Commission) related to the provision of products and services that are outside of traditional gas distribution utility activities. These "alternative energy services" applications have resulted in a series of *ad hoc* Commission decisions and orders. In a number of these proceedings, the Commission and Interveners have raised issues with respect to the scope and nature of regulation of these new business activities.

On December 14, 2010 and February 1, 2011, the Commission issued its Decisions on the FortisBC Energy Inc. (FEI) (then Terasen Gas Inc.[1]) Biomethane Application and the FortisBC Energy Utilities (FEU) 2012 Long Term Resource Plan, respectively. In both these decisions, the Commission considered issues related to utility ownership of assets up the supply chain, and the allocation of costs and risks for new business activities. The Commission indicated that a more formal process to determine how these new activities would fit within the context of a regulated utility would be required.[2,3]

On April 27, 2011, the Energy Services Association of Canada (ESAC), an industry association of energy service companies, requested the Commission exercise its general supervisory powers under section 23 (1) of the *Utilities Commission Act* (*UCA*) to inquire into the practices and conduct of FEI in the Alternative Energy Services (AES) market. (Exhibit A2-1)

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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] *In the Matter of An Application by Terasen Gas Inc. for Approval of a Biomethane Service Offering and Supporting Business Model and for the Approval of the Salmon Arm Biomethane Project and for the Approval of the Catalyst Biomethane Project*; Decision and Order G-194-10, December 14, 2010 (Biomethane Decision), p. 63.

[3] *In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. 2010 Long Term Resource* Plan; Decision and Order G-14-11, February 1, 2011 (2010 LTRP Decision), pp. 26-7.

ESAC raised the following concerns:

1. A lack of adequate public consultation by FEI;
2. The use and distribution of Energy Efficiency and Conservation (EEC) Funds by FEI;
3. FEI's role as a regulated utility in the delivery of AES and the potential cross-subsidization of AES activities by natural gas ratepayers; and
4. The inappropriate use of sensitive market information within FEU.

On May 24, 2011, the Commission issued Order G-95-11 which initiated this "Inquiry into FortisBC Energy Inc's Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives" (AES Inquiry). On July 8, 2011, by Order G-118-11, the Commission determined the AES Inquiry would: address issues at a principles level; focus on FEI (while recognizing that the principles set out may have application beyond FEI), and not re-open past Commission Decisions.

1.2 Objectives of the AES Inquiry

Over the course of this Proceeding, the Commission Panel has refined the Objectives of this Inquiry to be to:

a) Provide guidance to future Commission Panels dealing with applications related to new business activities;
b) Provide guidance to FEU and other utilities dealing with or entering into new business activities outside of the traditional gas distribution utility business;
c) Provide clarity as to the Commission's views on activities that should be regulated and activities that should be kept outside the regulatory umbrella;
d) Provide guidance as to how new activities that are to be regulated should be structured so as to be fair to the traditional ratepayer, the user of the new service and the utility;
e) Provide direction as to how EEC or other incentive funds should be administered to ensure fair, effective and non-discriminatory treatment;
f) Address specific issues referred to the Inquiry Panel from other proceedings; and
g) Provide direction to FEU as to a process to deal with the Thermal Energy Services Deferral Account.

1.3 Report Structure

The report is set out in four sections as described below:

- Section 1 - introduces the AES Inquiry and sets out its objectives.
- Section 2 - sets out key principles and guidelines to determine appropriate regulatory schemes for AES and New Initiatives.
- Section 3 - applies the principles and guidelines outlined in Section 2 to FEU's current AES activities and New Initiatives.
- Section 4 – deals with issues that have arisen over the course of the proceedings, including the allocation of hearing costs, EEC funding, the Thermal Energy Services Deferral Account (TESDA) and issues referred to the Panel from other Commission proceedings.

Throughout this Proceeding various terms have been used for the energy services at issue. For clarity, the terms "AES and New Initiatives" and "new business activities" are used to denote current and future offerings of products and services that relate to alternative energy sources to those offered by the traditional natural gas distribution utility. The terms AES and Thermal Energy Services (TES) are used somewhat interchangeably. For greater clarity, a glossary has been included as Appendix A.

1.4 Panel Approach in Setting out its Views

There is an extensive record in this Proceeding. The Panel acknowledges the valuable contribution made by all parties. Given the voluminous nature of the filed material, in the interest of clarity and readability the Panel decided to omit a detailed review of all of the positions taken. The Panel has endeavoured to show the reasoning behind its key findings.

1.4.1 Adoption of the RMDM Guidelines

Many of the issues in this proceeding are similar to those addressed in the Retail Markets Downstream of the Utility Meter (RMDM) Guidelines issued by the Commission in April 1997. (An excerpt from the RMDM Guidelines is included as Appendix D to this Report).

Those Guidelines describe three Commission objectives:

- "There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB[4], by utility ratepayers.
- The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers; and
- The most economically efficient allocation of goods and services for ratepayers should be sought."[5]

FEU and other parties to the proceeding endorsed the Objectives set out in the RMDM Report.

ESAC considers that "[t]he RMDM Guidelines are a useful starting point for guidelines to apply to the conduct of regulated utilities." Corix Utilities Inc. (Corix), a Registered Intervener, submits that these guidelines are appropriate and useful wherever different utility affiliates transact with each other. (ESAC Final Submission, para. 103; Corix Final Submission p. 20)

Dr. Jaccard, Corix's expert economist, notes that the new TES business being proposed by FEU is a return to the circumstances which existed at the time of the RMDM review in 1997. He recommends that the RMDM Guidelines be adapted to the new TES business. (Exhibit C12-5, pp. 18-19)

FEU endorse the Guidelines as they apply to non-regulated businesses (NRBs) but do not see them as relevant to determining the scope of regulation for new regulated business activities.

[4] Non-Regulated Business

[5] Retail Markets Downstream of the Utility Meter Guidelines, Exhibit B-1, Tab 17

Commission Determination

The Commission Panel finds that many of the objectives and principles of RMDM remain relevant and applicable today. In this Report, the Commission Panel has generally based its findings on RMDM and developed Principles and Guidelines that address areas, business structures and technologies beyond those addressed by RMDM. The Commission Panel especially confirms the RMDM principle "[t]here must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers" and extends this principle to apply to regulated businesses as set out in Sections 2 and 3.

SECTION 2 OVERARCHING ISSUES

This section sets out a framework of key principles and guidelines to determine an appropriate regulatory scheme for AES and New Initiatives. While the Panel's deliberations are based on the evidence relating to FEU's activities, the principles and guidelines can be applied to other utilities or firms looking to undertake similar business activities.

In general, firms looking to undertake AES or New Initiatives will be guided by this Section to determine first, whether the activity is regulated or not (Section 2.1) and second, the appropriate form of regulation for the activity (Section 2.2). Regulated utilities will be guided by the additional considerations in Sections 2.3-2.5 to determine the appropriate business structure, cost allocation and risk allocation for the activity.

2.1 Principles and Guidelines for Determining the Need for Regulation

Before a discussion can be held on how to regulate new business activities, it is essential to first determine if the activity requires regulation. The Panel assessed the extensive evidence provided on this matter, and reviewed decisions of the BC Court of Appeal and the Supreme Court of Canada. The Panel concludes that the determination of the need for regulation should be based on the principles and guidelines set out below. Given the fundamental importance of the determination of whether or not there is a need for regulation, this section sets out the basis for these findings by reviewing what constitutes a natural monopoly, the role of regulation, an outline of what regulation entails, the role of regulation compared to the role of competitive forces, the regulator's role vis à vis competition, the *Utilities Commission Act* requirements to regulate, and whether the Commission can control a utility's entry into a market or require greater separation of utility services.

Key Principles:

i) Only regulate where required.

ii) Regulation should not impede competitive markets.

Guideline

- Regulation is required when:
  - natural monopoly characteristics are present and there is a need to regulate to protect the public interest; and/or
  - legislation (such as the *Utilities Commission Act* or the *Clean Energy Act)*, requires an activity to be regulated.

Discussion

What Constitutes a Natural Monopoly?

Dr. Jaccard states "[n]atural monopolies occur in sectors of the economy in which extreme economies-of-scale mean the monopoly firm can provide service at a lower cost than two or more competing firms." (Exhibit C12-5, p. 7)

The market conditions which result in the creation of a natural monopoly may include:

- Large initial capital costs;
- Significant barriers to entry for competitors;
- Infrastructure which is not cost-effective or otherwise amenable to duplication;
- Subadditivity of costs: all the industry output (or array of outputs) demanded can be produced most efficiently only by a single firm; and
- Economies of scale, with decreasing costs or (internal) increasing returns to scale over the demanded range of output.

(Exhibit C12-5, p. 12; Exhibit B-11, BCUC IR 1.151.1)

In a market with natural monopoly characteristics, the lowest cost to provide a service can only be achieved by a single firm, and the presence of competition, or entry of other firms, would only serve to increase costs to society. (Bonbright *et al.*, 1988: 8, Exhibit B-11, BCUC 1.149.0)

Because a public utility tends to represent a single supplier of an essential product or service, its customers are basically captive, lacking the ability to readily change providers, and the demand curve is “inelastic”, such that a change in price will not result in an equivalent change in demand.

Public utilities are typically natural monopolies because their fixed costs, as determined by their technology and demand, are lower, such that it is a more efficient use of society’s scarce resources for a single firm to supply the market than multiple firms. (*ATCO*, para. 3[6])

The Role of Regulation

Monopolies may abuse their power by way of:

- Excessive Pricing - resulting in excess monopoly profits;
- Predatory Pricing- where the monopoly is able to discourage competitors from entering the market through pricing below cost in the short term;
- Cross-subsidization - excessive pricing in some areas, subsidizing low cost pricing in others.

Regulation exists to protect the public from potential monopolistic behaviour on the part of a public utility while ensuring the continued quality of an essential service.

It is the regulator’s function to prevent the abuse of monopoly power, so that customers have access to the utility product or service at a fair price, but at the same time allow the utility the opportunity to earn a fair return on its investment so that it can continue to operate and attract the capital required to sustain and/or grow its business.

The *Utilities Commission Act* is an example of public utility regulation that balances the public interest between monopoly, where monopoly is accepted as necessary, and the consumer protection provided by competition. (*BC Hydro v. BCUC*, para. 46[7])

[6] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4, [2006] 1 SCR 140

[7] *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)*, 1996 CanLII 3048 (BC CA)

What Does Utility Regulation Entail?

Regulation entails granting the monopoly the exclusive right to construct and operate plant and equipment, and provide services within a specific area, and to recover the costs of these activities in approved rates which are determined to be just and reasonable.

Regulation also involves an ongoing general supervisory role over the public utility, including its equipment and extensions of its works or systems. As noted by the Supreme Court of Canada in *ATCO*, "the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions." (*ATCO*, para. 4)

The Role of Regulation Compared to the Role of Competition

There are numerous examples in Canada dealing with the role of regulation versus the role of competition.

The *Ontario Energy Board Act* provides that the Ontario Energy Board, the public utility regulator in Ontario, is to refrain from exercising its power if it finds that, among other things, a class of products or services "is or will be subject to sufficient competition to protect the public interest." [8]

In the telecommunications industry, technological developments have, in large measure, removed the natural monopoly which had previously existed due to the wire infrastructure. The Canadian Radio-television Telecommunications Commission (CRTC) voiced the opinion that "regulation should focus primarily on services supplied on a monopoly (or near-monopoly) basis or in markets that are not yet workably competitive...Where markets are sufficiently competitive, market forces are generally preferable..."[9] The governing legislation for the CRTC, the *Telecommunications Act*, specifically provides for the CRTC to forbear from regulation in circumstances where it determined there was "competition sufficient to protect the interests of users..."[10]

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[8] *Ontario Energy Board Act,* 1998, SO 1998, c 15, Sch B

[9] Canadian Radio-television and Telecommunications Commission Decision 94-19 Review of Regulatory Framework, Exhibit A2-26, p. 9

[10] *Telecommunications Act*, SC 1993 c.38, ss. 34(1) as set out in CRTC 94-19, Exhibit A2-26, p. 27

The Competition Bureau of Canada "believes that a market can be deemed subject to sufficient competition to protect the public interest if no firm operating in it has sufficient market power to unilaterally and profitably impose a significant and non-transitory price increase." Its view, as outlined in a paper prepared by one of its members in respect of deregulation of portions of the electricity market, is that regulation should be avoided where there is sufficient competition to protect the public interest. (Exhibit A2-30, p. 7)

Dr. Jaccard, in this proceeding, states "[t]he underlying principle of economic regulation is that monopoly should only exist where it is not possible to replace it with competition. Competitive forces are accepted as providing societal benefits more efficiently and effectively than economic regulation." (Exhibit B-19, Appendix B, p. 10)

Dr. Ware, the expert economist retained by FEU, takes the position that "it is incorrect to argue that just because a product class can function as a competitive industry, then it is optimal to allow it to do so." He argues that "[t]here is a substantial literature on the sustainability of natural monopoly which highlights this regulatory dilemma." He quotes a 1977 article entitled: "Free Entry and the Sustainability of Natural Monopoly": "[a]lthough "free entry may encourage cost control and stimulate innovation", it may also encourage firms "with neither new products nor improved technology to enter the industry...The potential effects of such entry are higher overall costs and a reduction in the average welfare of customers." (Exhibit B-19, Attachment B, pp. 14-15)

The Regulator's Role Vis à Vis Competition

The British Columbia Utilities Commission and other sectoral regulators do not regulate competition *per se*, because that is the domain of the Competition Bureau. In Dr. Jaccard's submission, regulators try to foster competition where possible and constrain monopoly activities which might distort the competitive environment because regulation is typically a surrogate for a competitive market.

Dr. Ware argues that although a regulated utility may have a cost advantage in a new market resulting from its investments in its existing operations, these “economies of scope” result in a lower cost to the benefit of the marketplace. He is of the view that there is nothing inherently unfair about having FEI, in its position as a traditional gas distribution utility, enter the AES market and compete for AES projects. He argues that, as long as concerns relating to cross-subsidization and other issues are addressed, “FEI will bring an important competitive presence to the marketplace, and the rivalry generated by its participation will generate benefits for all TES customers.” (Exhibit B-19, Attachment B, pp. 8-9, 10-12)

The Regulator’s Role Vis à Vis Cross-Subsidization

Regarding cross-subsidization, Dr. Jaccard notes, “an ... important concern, especially for the utility regulator, is that the resources of the monopoly utility not be diverted into the competitive market in ways that might adversely affect its captive customers- its existing ratepayers.” (Exhibit C12-5, pp. 7-8)

Dr. Ware opines that appropriate regulation can prevent cross-subsidization between FEI’s traditional natural gas distribution utility and new AES activities. Dr. Ware suggests that the “term ‘cross-subsidization’ is often used and abused in equal measure.” He explains that the concept of “Stand Alone Costs” (being the cost to produce a single product class alone, without regard to any other activities in which the utility maybe engaged) and “Incremental Costs” (being the additional cost to add a product class given that the utility is already operating) represent the bounds within which a product is said to be “subsidy free” and no cross-subsidization is occurring.

He notes that the incentive to cross-subsidize for FEI is mitigated as both its gas utility business and the TES market will be regulated, and, more importantly, that the regular rate hearings for the FEI gas utility business, which entail extensive scrutiny, would reveal the presence of any cross-subsidization. (Exhibit B-19, Attachment B, pp. 8-13, 15-16)

Dr. Jaccard explains that, although regulating monopolies with extreme economies-of-scale may provide benefits to society, natural monopoly conditions are not static and the regulator must pay close attention to changes in market conditions, government regulations and technologies to identify situations where natural monopoly conditions may no longer exist, or, in the case of a new market, not yet exist. (Exhibit C12-5, p. 10)

This approach can also be seen as a staged approach where, prior to the establishment of a competitive market, the sectoral regulator acts, and may attempt to enable competition, but, once competition is established, the Competition Bureau will take over and monitor the behaviour of competitors.

Utilities Commission Act **Requirements to Regulate**

The legislative requirement to regulate is, in British Columbia, governed mainly by the *Utilities Commission Act* which defines a "**public utility**" as meaning:

> a person... who owns or operates in British Columbia, equipment or facilities for
>
> > (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation, or...
>
> but does not include...
>
> > (c) a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries,
> >
> > (d) a person not otherwise a public utility who provides the service or commodity only to the person or the person's employees or tenants, if the service or commodity is not resold to or used by others,
> >
> > (e) a person not otherwise a public utility who is engaged in the petroleum industry [defined in the *Act* as, in part, (e) the retail distribution of liquefied or compressed natural gas] or in the wellhead production of oil, natural gas or other natural petroleum substances,

> (f) a person not otherwise a public utility who is engaged in the production of a geothermal resource[11], as defined in the *Geothermal Resources Act*, or
>
> (g) a person, other than the authority, who enters into or is created by, under or in furtherance of an agreement designated under section 12 (9) of the *Hydro and Power Authority Act*, in respect of anything done, owned or operated under or in relation to that agreement;

Considerable debate occurred in this Proceeding on the interpretation of the definition of a public utility in the *UCA*.

The FEU's initial position was:

> "[t]he *Utilities Commission Act* dictates what services are regulated through the definition of public utility in section 1 of the *UCA*. There is no discretion embedded in the definition of public utility; either it applies to an entity or it does not. The Commission is not empowered to decide, as a matter of regulatory policy, that certain entities which otherwise meet the definition are not subject to the *UCA."* (Exhibit B-2, p. 171)

ESAC submits that such an interpretation is overly broad and could lead to the absurd result that sellers of "light bulbs; flashlights; lighters; household appliances such as stoves, ovens, microwaves, kettles, refrigerators, freezers, and air conditioners; furnaces; boilers; hot water tanks; space heaters; camp stoves; barbeques; fuels such as wood, coal, charcoal and biofuels of various kinds; and batteries; etc.", for example, are public utilities. (ESAC Final Submission, para. 45)

The FEU now submit that the definition of "public utility" must be read harmoniously with the purpose of the *UCA*, namely "to regulate natural monopolies and also to protect consumers from the exercise of economic power." (FEU Reply Submission, para. 35) FEU also accept that the size of the service and the market barriers affecting the potential for the service provider to become a monopoly supplier after the fact are considerations in determining whether a service meets the definition of public utility. (FEU Reply Submission, paras. 39-40)

[11] The definition of geothermal resource from the *Geothermal Resources Act* does not apply to the typical geo-exchange systems discussed in this Decision.

Commission Determination

Regulation exists to protect consumers against the abuse of monopoly power but, in the Commission Panel's view, the superior protection for consumers is the competitive marketplace. The Commission Panel accepts Dr. Jaccard's statement that "[t]he underlying principle of economic regulation is that monopoly should only exist where it is not possible to replace it with competition." This is consistent with the first principle outlined in this Section, to only regulate where required. Competitive forces are generally accepted as providing societal benefits and consumer protection more efficiently and effectively than economic regulation. The Commission Panel further notes that this premise is not disputed by FEU's expert, Dr. Ware, who takes the position that, subject to certain safeguards, it is possible for a monopoly service provider to enter a market and compete fairly in a way that will generate benefits for all customers.

Regulation is costly, time-consuming, and limited by informational asymmetries. It is only in natural monopoly situations where consumer protection is needed that these limitations are outweighed by the benefits of regulation.

Based on the above, the Commission Panel finds as a fundamental principle that regulation is only appropriate where required and is driven by the inability of competitive forces to operate with greater efficiency and effectiveness than a sole service provider.

While the Commission does not regulate competition *per se*, the Panel accepts that it should not act to hinder competition, where competition is feasible. In this regard, the Commission Panel confirms that there must be no cross-subsidization when a utility purports to enter a competitive market.

Regarding regulation as a choice in a competitive market, FEU and certain Interveners have argued that the regulated cost of service model is simply another choice or "value proposition" which should be available to the thermal customer. Corix and ESAC take a counterview that the *UCA* must be applied consistently and that an activity is either regulated within the definition of "public utility" under the *UCA* or not.

The Panel finds that customer preference does not determine the need for regulation. Regulation itself is not a choice. The need for regulation is determined by natural monopoly characteristics, the resulting need for consumer protection and/or the relevant legislation.

The legislative requirements to regulate are defined in British Columbia by the *UCA*. The Commission Panel agrees that a strict, literal interpretation of the definition of "public utility" in the *UCA* could lead to an absurd result such that a host of services and technologies that are available in a competitive marketplace would require regulation. Accordingly, the Commission Panel must do its best to interpret the legislation and does so following the legal test set out in *Rizzo*[12] i.e., that the grammatical and ordinary sense of the words must be read "harmoniously" with the purpose of the Act.

The Commission Panel agrees that the purpose of the *UCA* is to regulate natural monopolies and protect consumers from the exercise of economic power. The Commission Panel is of the view that a reasonable interpretation should consider the market context within which the proposed service or facility will exist, the degree to which natural monopoly characteristics are present and whether the consumer requires protection. **The Commission Panel finds that in general, a provider of services which meets the definition of a public utility in the *UCA*, and where natural monopoly characteristics are present and consumers require protection, will be subject to regulation.**

The definition of public utility is set out in the *UCA* but, given the discussion on the economic purposes of regulation, applying the legal definition of public utility does not always lead to an outcome that makes the most economic sense. The Panel notes that the *UCA* was developed at a time when many of the technologies at issue in this Proceeding were not contemplated. The current energy market requires a practical definition of public utility. There would be greater clarity if the Government were to explicitly amend the *UCA* to exclude regulation of activities

[12] *Rizzo & Rizzo Shoes Ltd.* (RE), [1998] 1 SCR 27

where competitive forces are found to provide sufficient protection to the public[13]. Given the current lack of clarity in the *UCA* the Commission Panel recommends the use of exemptions, which are contemplated under the *UCA,* where the Commission finds regulation is not warranted.

Can the Commission Control a Regulated Utility's Entry into a Market or Require Greater Separation of Utility Services?

The RMDM Guidelines state:

> "[t]he Commission has the jurisdiction to prohibit a public utility from participating in retail markets downstream of the meter if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers." (RMDM Guidelines, p. 21)

Ferus Inc., LNG Division (Ferus LNG), an Intervener in the Inquiry, argues that this principle is still relevant and takes the position that the Commission has the jurisdiction in appropriate circumstances, to prohibit a public utility from participating in a market, or to require greater separation of utility services. Ferus LNG submits that this jurisdiction is not only grounded in the Commission's traditional ratemaking jurisdiction but now also in broader public interest considerations, such as the promotion of British Columbia's Energy Objectives. Prohibiting a utility from participating in a market or requiring greater separation is, in Ferus LNG's submission, the only reasonable and effective means to further BC's Energy Objectives such as the development of the clean energy industry in BC. (Ferus LNG Final Submission, pp. 8-10)

FEU argue "that the approach of having as a 'starting point' full corporate separation is inconsistent with section 60(1) [of the *UCA*], unnecessary and undesirable." (FEU Final Submission, para. 99)

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[13] For example, the *Ontario Energy Board Act* states: "On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest." *Ontario Energy Board Act*, 1998, SO 1998, c. 15, Sch. B, s. 29 (1).

Corix submits that "multiple utilities within the same corporate entity should be permitted only if the Commission is satisfied that cross-subsidization risks have been address and the public interest has been taken into account." (Corix Final Submission, p. 25)

Commission Determination

The Commission Panel finds that it does have the jurisdiction to control a public utility's service offerings and/or to require greater structural separation between services for the reasons advanced both in the RMDM Guidelines proceeding and by Ferus LNG.

The Commission further finds that this jurisdiction stems from its jurisdiction over a utility's investments, through such processes as applications for Certificates of Public Convenience and Necessity. In *BC Hydro v. BCUC* the Court of Appeal noted that "[t]he certification process is at the heart of the regulatory function delegated to the Commission by the legislature...The other function the legislature has entrusted to the regulatory tribunal is the supervision of the utility's use of property dedicated to service as the result of the certification process." (paras. 48, 49)

In *ATCO*, the Court explained that "[a]s in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. <u>However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions.</u>" [Emphasis added] (para. 4)

From the above, it can be concluded that the regulator, through the certification process, as well as through cost recovery approval mechanisms, can limit a utility's service offerings or, in other words, can limit the markets a utility may enter.

2.2 Principles and Guidelines for Determining the Form of Regulation

Once an activity is found to require regulation, the appropriate form of regulation must be determined. Regulation itself runs a spectrum from what could be considered full and more onerous regulation, which is often based on the fully allocated cost of service of the utility, or rate base/rate of return "earnings" regulation, to the most light-handed form of regulation, being forbearance and/or regulation by complaint. The form of regulation is not dependent on the business structure through which the regulated activity is to be delivered. The Panel finds that the form of regulation to be used should be driven by the principles and guidelines set out below.

Key Principles:

i) Where regulation is required use the least amount of regulation needed to protect the ratepayer.
ii) The benefits of regulation should outweigh the costs.

Guidelines:

- The form of regulation should:
  - provide adequate customer protection in a cost effective manner;
  - consider administrative efficiency;
  - consider the level of expenditure, the number of customers, the sophistication of the parties involved and the track record of the utility in undertaking similar projects; and
  - require the provision of sufficient information to allow the Commission to assess the new business activity, and any rates to be set, against BC's Energy Objectives and the requirements of the *Utilities Commission Act* and the *Clean Energy Act*.

Discussion and Commission Determination

While the rate base-rate of return-cost of service model is the most common type of regulation used by the Commission, options available to the Commission include, but are not limited to:

- Rate base - rate of return - cost of service regulation;
- Performance based regulation;
- Negotiated settlements;

- Limited exemptions from regulation;
- Market based pricing; and
- Regulation by complaint.

Regulation in and of itself imposes significant costs on the utility ratepayer. It is important that these costs do not exceed the benefits derived. Hence, the question "what is the least amount of regulation needed to protect the interests of ratepayers"?

For new business activities, the least amount of regulation to protect customers may involve different considerations depending on the characteristics of the activity. If, for example, a new regulated activity has only limited monopoly characteristics and limited consumer protection is needed, there may be opportunities to use lighter handed forms of regulation such as market based pricing or regulatory exemption. This would be the case where the Commission found that there were sufficient market forces at play to protect the interests of the ratepayer. Long term contracts setting out rates and terms and conditions of service may also provide sufficient consumer protection under light handed regulation. In other instances, it may be appropriate for the Commission to closely scrutinize new business activities until there is a track record related to the performance of this type of activity. Once such a track record is achieved, and the Commission has benchmarks or a basis of comparison upon which to judge new applications, a lighter handed form of regulation may be appropriate. The cost of service methodology, or, the "model of last resort"[14], is unsuited to many projects that are regulated under the *UCA*, especially those with few natural monopoly characteristics and which require little consumer protection.

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[14] In the Delta School District Decision, the Panel stated: "In a competitive environment, the Panel is not convinced that a COS [cost of service] model, where any cost overruns are paid by the ratepayer, is the most appropriate pricing model as competition itself will incent the service provider to determine a fair price. It is clear that the own/operate model contains much stronger built-in incentives to increase efficiency, reduce costs and enhance performance, which a regulator would struggle to emulate within the COS model. In the presence of an actively competitive market, there appears to be no reason to apply a model which was developed to be a surrogate for competition. The Panel sees the traditional COS rate-base model as the 'model of last resort' that was initially developed for traditional utilities with natural monopoly attributes." (p. 83)

2.3 Principles and Guidelines for Determining Business Structure and the Use of Monopoly Resources

Introduction

In the traditional natural gas utility, natural gas is typically purchased from a producer, and transported to the distribution utility through a provincial or interprovincial pipeline. The utility then distributes the gas through its network of pipes to a variety of customers within its franchise territory.

When an existing regulated utility enters into a new line of business, it is necessary to determine the degree to which the new activity can or should be integrated into the existing organizational structure. There is a spectrum of options varying from complete integration within the traditional natural gas distribution utility to complete separation as illustrated below.

Integration ⟵⟶ **Separation**

One class of service/ class of customer	Separate Class of of Customer	Separate Class of Service	Affiliated Regulated Business	Affiliated Non-regulated Business

The business structure affects the potential for cross-subsidization between the traditional monopoly natural gas utility ratepayer and the ratepayer of the new business activity. The potential for cross-subsidization is of most concern where the new activity is to be undertaken in a market which is competitive, or has the potential to be so. The Panel has developed the following guidelines setting out which of the various business structures is most appropriate for a new business activity.

2.3.1 Non-Regulated Businesses

The topic of when regulation is needed or required has been discussed at some length in Section 2.1. Where it is found that a new business activity is not regulated the Panel finds the following principles and guidelines to be appropriate.

Key Principle:

i) The Commission Panel reaffirms the following RMDM objectives:

- "There must be no subsidy of unregulated business activities, whether undertaken by the utility or its [non-regulated business], by utility ratepayers."
- "The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers."
- "The most economically efficient allocation of goods and resources for ratepayers should be sought." (RMDM Guidelines, p. 23)

Guidelines:

Under RMDM it was determined that "[u]tility participation in the unregulated downstream market by completely stand-alone[15] [non-regulated businesses] using no utility resources is the preferred option since it provides the maximum protection to utility ratepayers. Variations from this option should be undertaken only when it can be shown that this option would result in substantial stranded costs for the utility and/or that a transfer pricing policy mechanism will act to provided sufficient protection for ratepayers."

Where activities undertaken as a related non-regulated business do involve sharing of resources, the following Guidelines apply:

- An approved Code of Conduct and Transfer Pricing Policy must be in effect and require:
  - minimal sharing of resources between regulated and non-regulated affiliates; and
  - use of the full cost to provide the service or market pricing, whichever is higher.
- All costs and services provided between a Regulated and a Non-regulated Affiliated Business are to be fully disclosed to the Commission.
- To the extent that information is shared by a Regulated Business with a Non-regulated Business, it must also be shared with any interested non-related business.
- The following principles from RMDM remain valid:
  - "The onus should always be on the utility to prove that the benefits associated with the use of utility resources are sufficient to warrant the changed structure and that the transfer pricing policy mechanism will provide sufficient protection to ratepayers."

[15] "Stand-alone Non-Regulated Businesses" use no utility facilities or services, and Related Non-Regulated Businesses use some utility facilities and services. Both business types are set out in the RMDM guidelines.

- "If the commission decides to allow the use of utility resources in the provision of the unregulated good or service, the preferred option is through a related-NRB. Direct participation by the utility in the provision of an unregulated good or service should be allowed only when the costs associated with forcing the provision through the related-NRB structure would significantly offset the benefits associated with the use of the utility's resources and it can be shown that a transfer pricing policy mechanism will provide sufficient protection for ratepayers."
- "Utilities and their related-NRBs will be encouraged to move unregulated products which use utility resources into stand-alone NRBs as soon as market conditions warrant. When a utility-provided product is moved to an NRB, the NRB will be required to pay fair market value to the utility for the assets, including goodwill, associated with the product. In addition, utilities will be required to provide periodic proof that the benefits associated with the use of utility services continue to exist and that ratepayers continue to be sufficiently protected. The Commission will make directions to prohibit the use of utility assets and services in the provision of goods and services downstream of the retail market at any time that it finds it in the interests of ratepayers to do so." (RMDM Guidelines, p. 24)

Discussion and Commission Determination

FEU and other parties to the proceeding endorsed the Objectives set out in the RMDM Report. However, FEU argue that the third RMDM objective, that the most economically efficient allocation of goods and services must be sought, provides a rationale for them to provide a competitive service within a regulated utility where economies of scope make the utility the low cost provider of the new business activity. (FEU Reply Submission, p. 1)

The Commission Panel has previously determined that many of the objectives and principles of RMDM remain relevant and applicable today. Specifically, the Commission Panel finds the guidelines of RMDM that relate to Non-Regulated Businesses are valid and confirms them.

New business activities with no natural monopoly characteristics should be carried out by a stand-alone or related non-regulated business and not by a regulated utility unless specifically required by legislation. Where a utility seeks to participate in an activity where there are no monopoly characteristics, the utility must demonstrate that its participation is necessary and in the public interest, to the exclusion of other forms of enterprise. If the utility is to provide the new business activity as a Non-Regulated Business, there must be an approved Transfer Pricing Policy and Code of Conduct to prevent cross-subsidization.

Where resources are provided by a corporate parent, fewer concerns with cross-subsidization arise than when resources are shared between a traditional utility and a new business activity.

The Commission Panel notes there are examples of more detailed Codes of Conduct such as the FortisAlberta Inc. Code of Conduct as approved by the Alberta Energy and Utilities Board in 2005. (Exhibit A2-15) **The Panel recommends that the FEU initiate a process to prepare an updated Code of Conduct and Transfer Pricing Policy in respect of the interaction between the regulated utilities and related non-regulated businesses. This should be done through a collaborative process involving the utilities, stakeholders (including Interveners in this proceeding) and Commission staff. The Commission recommends that participants in this process should consider the Principles and Guidelines outlined herein as well as the FortisAlberta Inc. Code of Conduct. The Panel recommends that this process be initiated as soon as is practicable. The updated Code of Conduct and Transfer Pricing Policy should be submitted to the Commission for approval.**

2.3.2 Regulated Businesses

Where a new business activity is subject to regulation, it will be necessary to determine the degree of integration of that new activity with the existing public utility. The options range from the use of an affiliated[16] regulated company to full integration within an existing class of service. The Panel finds that application of the principle outlined below provides the foundation for assessing the appropriate business structure.

Key Principle

i) The business structure for a new regulated business activity should be determined on the basis of the degree of integration or separation that is appropriate to:

[16] The Panel uses the term "affiliated" to mean stand-alone and related, as those terms are used in RMDM. For clarity, stand-alone is where no utility facilities or services are used and related is where some utility services and facilities are used.

- provide the necessary protection to the traditional utility ratepayer from subsidizing the new business activity;
- provide a fair and reasonable allocation of risk among utility ratepayers, the new business ratepayers and the utility shareholder; and
- allow for fair allocation of costs and benefits among different groups of customers.

Discussion and Commission Determination

A major issue in dealing with new business activities proposed by an existing regulated utility is the degree to which the new activity is integrated within the existing organizational structure.

The Commission in the Delta School District Decision found that greater separation "allows for: easier evaluation and measurement of segments, future divestiture, clearer reporting, improved transparency and cost accuracy, clearer cost allocation, reduced possibility of cross-subsidization, improved objectivity and regulatory efficiency through simpler rate setting."[17] (Delta School District Decision, p. 95)

In the view of the Panel, an appropriate business structure should:

- adequately protect the public interest;
- protect against cross-subsidization among ratepayer groups;
- provide a fair and reasonable allocation of risk among existing ratepayers, the new business ratepayers and the utility shareholder; and
- allow for fair cost allocation among different groups of customers.

In many cases, the choice of business structure is based on a judgment as to the degree of separation that will provide the most cost effective means to ensure appropriate cost and risk allocation. Where the new business is more fully integrated into the structure of an existing utility, cost and risk allocation may require complex methodologies and more detailed scrutiny of utility activities than will be the case in a less integrated model. In keeping with the Delta School District

[17] *In the Matter of An Application by FortisBC Energy Inc. for a Certificate of Public Convenience and Necessity for Approval of Contracts and Rate for Public Utility Service to Provide Thermal Energy Service to Delta School District Number 37;* Order G-31-12, March 9, 2012 (Delta School District Decision)

Decision, the Panel finds a greater reliance on structural separation as opposed to the use of accounting will minimize the potential for abuse. Such separation will make it easier for the Commission to assess whether the allocation of costs and risk has been undertaken in a fair and reasonable manner.

The following guidelines provide assistance in determining the type of business structure that will achieve the objectives set out above. The guidelines also provide additional clarity for the use of natural gas monopoly resources in Affiliated Regulated Businesses.

2.3.2.1 Affiliated Regulated Businesses

The use of an Affiliated Regulated Business to pursue a new regulated business activity provides the greatest degree of business separation for regulated activities.

Guidelines:

- Structuring a new regulated business activity as an Affiliated Regulated Business is most appropriate when some or all of the following characteristics are present:
    - The new regulated business activity takes place largely beyond the delivery meter of the traditional utility;
    - The new regulated business activity has limited or no use of the traditional utility assets; and
    - The new regulated business activity has the potential to impose higher risks on the users of the new service and/or the utility shareholder.
- An approved Code of Conduct and Transfer Pricing Policy should govern interactions between Affiliated Regulated Businesses and the natural gas monopoly (the traditional utility);
- Common corporate and management resources may be shared between two Affiliated Regulated Businesses that are natural monopolies, such as gas and electric service;
- The sharing of any common resources between a natural monopoly affiliate and an affiliate that is a regulated business in a non-natural monopoly environment, however, should be much more limited. As a rule, resource sharing should be limited to corporate services and should not include any operational services except possibly emergency services;
- Sharing of employees should not be allowed where the employee has access to confidential information, routinely participates in making decisions with respect to the provision of traditional utility services or how utility services are delivered, routinely deals with or has

direct contact with customers of the utility or is routinely involved in planning or managing the business of the traditional utility;

- All sharing of costs, services and information between affiliated utilities must be fully disclosed to the Commission.

Discussion and Commission Determination

Greater separation is needed when there is an increased risk of cross-subsidization from the traditional utility and where the new business activity presents a different risk profile.

The level of use of the traditional gas utility infrastructure by the new business activity can indicate the degree of separation required. Many of the new business activities being initiated by FEU involve incidental or no utilization of the traditional natural gas distribution utility infrastructure. For example, district energy systems may utilize new technologies such as geothermal ground loops that have no relationship to the distribution of natural gas. These systems may be backed up by gas boilers, but this is an incidental use of the distribution system that is no different than would occur if the district energy system were a residential or commercial customer. The assets being regulated in this case, even if they are gas related assets such as centralized high efficiency gas boilers serving a district energy system, lie outside the traditional gas distribution system. In these cases, a greater degree of corporate separation is warranted.

The risk profile is another characteristic that can determine the requisite amount of separation. For example, it is important that the traditional natural gas utility be insulated from the risk posed by a new business activity. Maintaining the TES activity within the regulated gas distribution utility makes it more difficult to insulate the traditional natural gas ratepayer from the costs associated with the increased risk driven by the new activity. As well, FEU has stated that the TES activities carry a higher degree of risk than the traditional gas distribution business. A separate regulated affiliate facilitates the establishment of a separate approved rate of return and/or capital structure that reflects the risk profile of the TES business activity.

New business activities may also be operating in an environment where there are competitive elements to the activity. For example, there may be several companies competing to provide a district energy system to a proposed new development. The use of a separate regulated business to undertake this activity will reduce the likelihood of distortions to the competitive market environment resulting from any inappropriate transfers, such as cross-subsidization. Given the findings in Section 2.1 that the competitive market environment provides the best form of protection for consumers, the most desirable business structure for a regulated utility is one that allows the competitive market to operate freely and without distortion. The use of a separate regulated affiliate reduces the likelihood of such distortion.

The Fortis group of companies already includes Affiliate Regulated companies. FEU provide regulated gas service, for example, while FortisBC Inc. provides a regulated electric service. The capital assets of FortisBC Inc. are related to the generation, transmission and delivery of electricity and are quite separate and distinct from FEU's capital assets, which are used for the distribution of natural gas. This does not preclude the use of some common resources between these two natural monopolies where it is in the interest of the ratepayers of both utilities. It is important that there is a clear understanding of how interactions between Affiliated Regulated Businesses are to be governed. Therefore, it is recommended that an approved Code of Conduct and Transfer Pricing Policy be in place.

A larger concern, however, is the sharing of common resources between the natural gas monopoly (or any natural monopoly business) and a regulated business affiliate operating in a non-natural monopoly environment. As interactions between regulated affiliated utilities with very different characteristics have not received the same degree of attention in the past as have interactions between a utility and its non-regulated affiliates, extra care must be taken in developing a proper Code of Conduct.

To this end, the Panel recommends that the FEU undertake a collaborative process to establish a Code of Conduct and a Transfer Pricing Policy governing the interactions between Affiliated Regulated Businesses, consistent with the Principles and Guidelines set out in this Report. These

documents should differentiate resource sharing between two natural monopolies on the one hand and between a natural monopoly and a regulated affiliate operating in a non-natural monopoly environment on the other.

This process should be carried out in an expeditious manner, involving the utilities, stakeholders (including Interveners in this proceeding) and Commission staff. The Panel further recommends that the participants in this process use the Fortis Alberta Inc. Code of Conduct as a guide. The process should include the review of the Code of Conduct and Transfer Pricing Policy between FEU and non-regulated businesses as recommended in Section 2.3.1.

2.3.2.2 Separate Classes of Service

A closer integration of a new business activity into the structure of the existing regulated utility through the use of a separate class of service is warranted in instances as set out in the following guidelines and discussion.

Guidelines

- Structuring a new regulated business activity as Separate Class of Service within the Regulated Utility is most appropriate when some or all of the following characteristics are present:
  - The new regulated business activity largely uses and is dependent on the traditional gas utility distribution infrastructure but with additional clearly identifiable costs and/or assets that pertain specifically to the new business activity;
  - The risk of the new business activity differs from the risk faced by the traditional natural gas ratepayer; and
  - An identifiable customer base is served by the new regulated business activity.

Discussion and Commission Determination

The creation of separate classes of service is contemplated in the "Setting of Rates" section of the *UCA* (Section 60 (1)(c)) which states:

> (c) if the public utility provides more than one class of service, the commission must

> (i) <u>segregate</u> the various kinds of service into distinct classes of service,
>
> (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a <u>self contained unit</u>, and
>
> (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit. [Emphasis added]

A separate class of service therefore provides some degree of ring-fencing from other classes of service within the traditional utility. This allows for greater transparency and facilitates the appropriate allocation of costs to users of the service.

New regulated business activities that have the characteristics listed above generally require some separation from the traditional utility to prevent cross-subsidization and risk transfer to the traditional utility ratepayer. These new business activities may have unique costs relevant to that service but are still dependent on the assets of the traditional natural gas distribution utility. In these cases, the need for separation is not as great as when the new regulated business activity uses separate assets.

Where the risks of providing the new service are different from the risk of the existing gas distribution system a Separate Class of Service may be appropriate. Compared to undertaking the activity in a separate affiliated regulated utility, the separate class of service could increase risk to existing ratepayers, for example, from stranded assets related to the new business activity. Where the risk of costs flowing back to the traditional regulated ratepayer is found to be minimal, a separate class of service may be appropriate.

2.3.2.3 Separate Class of Customers

From an economic point of view, if a new business activity were to involve only the use of the traditional distribution system with no upstream or downstream coomponents, it might be appropriate to manage the new activity as part of the existing natural gas service, but with a separate class of customers[18].

Guidelines

- Structuring a new regulated business activity as a Separate Class of Customers within the regulated utility is most appropriate when some or all of the following characteristics are present:
  - The new regulated business activity uses the traditional utility distribution infrastructure to serve a specific set of customers attached to the utility;
  - The new regulated business activity does not include assets beyond the traditional utility;
  - The risk incurred in adding the new class of customer is comparable to the overall risk faced by the existing customers; and
  - There are identifiable sets of customers with common characteristics receiving a common set of services. These customer groups may be established to facilitate a rate design that provides an acceptable cost allocation for the provision of the common set of services.

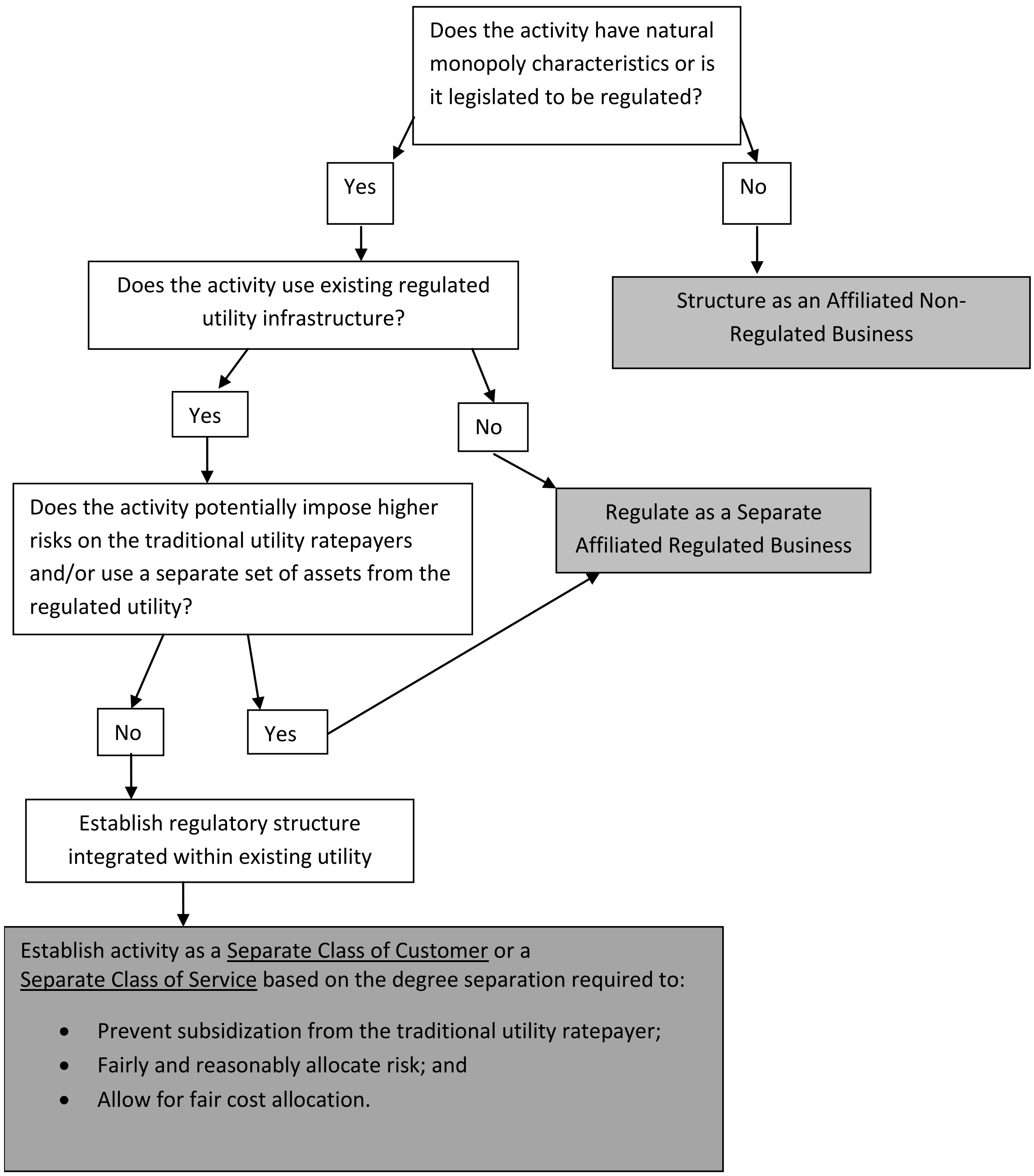
Discussion and Commission Determination

A class of customer within the traditional regulated utility represents the least amount of separation contemplated in the spectrum of options. This structure can be used when there is little need to prevent cross-subsidization of costs and risks from the traditional utility to the new regulated business activity.

[18] A class of customer is a group of individuals taking service under the same rate schedule. Common examples are residential, commercial, and industrial customers.

Decision Flowchart – Assessment of a New Business Activity

The flow chart below illustrates how the Guidelines can be used by future Commission Panels to determine the business structure that best meets a given set of circumstances.



2.3.3 Extension of Ownership for Regulated Utilities

An additional issue is - when is it appropriate for a regulated utility to own assets that are not part of the traditional regulated utility? In entering into new business activities a utility may consider acquiring assets that are located upstream of the receipt meter or downstream of the delivery meter of the traditional gas distribution utility. The Panel has set out Principles and Guidelines for when such acquisitions should be allowed.

Key Principle:

i) The ownership of facilities by a regulated utility outside of the bounds of the traditional gas distribution utility is not recommended where there are viable alternative options and should only be allowed in exceptional circumstances, or where required by legislation.

Discussion and Commission Determination

As discussed earlier, cross-subsidization by the traditional utility ratepayer is an issue in this Proceeding. Therefore, to reduce the likelihood of cross-subsidization, the Panel finds that ownership of facilities by a utility outside the bounds of the traditional utility system should not be allowed unless there are extenuating circumstances that make such ownership in the public interest. The onus is on the utility to prove that such extenuating circumstances exist.

2.4 Principles and Guidelines for Determining Cost Allocation for Regulated Utilities

A key issue under any regulated business structure is cost allocation. The Commission Panel is mindful that to achieve the objective of fairness in cost allocation, the principle that those causing costs should be responsible for paying them must be followed. No party in this proceeding took exception to this rule. How best to achieve the goal of cost causality was a focus of many of the Interveners, with a variety of positions taken. Based on the evidence provided, the Panel came to the views as set out below.

Key Principle:

i) The basis of cost allocation is cost causality.

Guidelines:

- For those new business activities provided through a Regulated or Non-Regulated Affiliated Business or a Separate Class of Service, costs are to be allocated to the new business or shareholder, on the basis of the higher of market price or the fully allocated cost, and be free of all forms of cross-subsidization from the traditional utility. These costs include both direct costs and a fair allocation of the parent utility costs required to provide the product or service. An exception to this rule would be any cost handling which has been prescribed by legislation, regulation or special direction.
- Allocation of costs is to reflect appropriate compensation for any benefit derived by the new business activity as a result of its affiliation with its parent or other businesses. This should include compensation for additional cost or risk related to the addition of incremental debt to the parent utility for the new products or services.
- A service provided by the parent utility, or from one class of service or affiliate to another class or affiliate, will be on the basis of an approved Transfer Pricing Policy.
- There should be transparency in cost allocation among different customer groups.
- All proposals for new business activities must be accompanied by a clear and concise description of the planned cost allocation methodology.

For an Affiliated Regulated Business, the specific guidelines set out below should be followed:

- A Commission approved Code of Conduct must govern interactions;
- Any sharing of costs and services between Affiliated Regulated Businesses must be done on the basis of the higher of market price or the fully allocated cost, in accordance with a Commission approved Transfer Pricing Policy; and
- All sharing of costs, services and information between affiliated regulated utilities must be fully disclosed to the Commission.

When an activity is determined to be in a Separate Class of Service, the following guideline should be followed:

- All costs of establishing the new business activity taking place under the new Separate Class of Service should be borne by the new class of service or the utility. The traditional natural gas distribution ratepayer should be shielded from all such costs.

Discussion and Commission Determination

For new products or services using an existing class of service, FEU argue that allocation of costs among different customer groups within the utility is a matter of rate design. FEU state that the fundamental test in rate design as mandated by the *UCA* is that rates must not be unduly discriminatory or preferential. Imbedded within this is the principle of "cost causality" with the provision that those causing costs should be responsible for them. (FEU Final Submission, p. 41)

The Panel does not believe that the principle of cost causality suggests any significant change to the practices that have been consistently followed by the Commission. The aim of this principle is to have customers bear the share of costs that are attributable to their service, to prevent cross-subsidization among customer groups.

For new business activities, the challenge lies in determining the costs that should be borne entirely by the new business customer (or the utility shareholder). An approved Transfer Pricing Policy should ensure that costs are allocated on the basis of the higher of fully allocated cost or market pricing and an approved Code of Conduct should ensure that the sharing of operational and management services is appropriate.

Interactions between affiliated regulated utilities have not received the same degree of attention in the past as have interactions between a regulated utility and its non-regulated affiliates. Although the FEU 2012-2013 RRA Decision[19] accepted the use of the Transfer Pricing Policy for cross-charges between FEU and its Affiliated Regulated Business, FortisBC Inc., the Commission Panel believes that in light of the Principles set out in this Inquiry, it is appropriate to provide greater clarity around the form and nature of interactions between Affiliated Regulated Businesses. The affiliated regulated utilities have distinct sets of ratepayers and it is important that each ratepayer group is properly protected.

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[19] *In the Matter of An Application by The FortisBC Energy Utilities Inc. for the 2012-2013 Revenue Requirements and Rates,* Decision and Order G-44-12, Dated April 12, 2012. (2012-2013 RRA Decision)

2.5 Principles and Guidelines for Determining Allocation of Risk for Regulated Utilities

Risk allocation is the assessment of how costs will be allocated in the case of unforeseen events. Failure of the business to develop as expected is an example of an unforeseen event. When a utility enters a new business, the issue of allocation of additional risk to: (1) the traditional utility ratepayer; (2) the new business ratepayer; and (3) the shareholder, arises. The Panel sets out the following Principles and Guidelines to ensure fair and reasonable allocation of risk associated with a new business activity.

Key Principles:

i) The traditional ratepayer is to be free of risk for a new product or service to be distributed through an Affiliated Regulated Business or a Separate Class of Service.

ii) Within Regulated Affiliates or Separate Classes of Service, there is to be a fair balance of risk and reward between the customer and the shareholder.

iii) If a utility seeks a higher rate of return (i.e. a risk premium) for its investments related to a new business activity, the utility shareholder must bear the additional risk, and not the traditional natural gas ratepayer. The incremental cost burden to customers resulting from an approved higher rate of return should be borne by the users of the new business activity and not by the traditional gas distribution utility ratepayer.

Guidelines:

- The risk of unrecovered costs (including, but not limited to, start up, operating and capital costs) is to be borne by the Affiliated Regulated Business or Separate Class of Service or the shareholder. If costs related to the new business activity cannot be recovered from new business customers in a reasonable period of time (as approved by the Commission) these costs will be borne by the shareholder.
- All proposals for new business activities should be accompanied by a risk management plan. The risk management plan should address:
  - The anticipated level of risk that would be faced by the traditional ratepayer, the new business ratepayer, and the shareholder; and
  - How the incremental costs from these risks will be allocated among these groups.

Discussion and Commission Determination

An issue in this proceeding is the allocation of the risk associated with the recovery of start-up costs, operating costs and wind-up costs to natural gas service customers and to Thermal Energy Service Customers. FEU argue just as prudently incurred costs related to natural gas service customers should be recoverable from those customers, prudently incurred costs for a new business service, such as Thermal Energy Service, should be recoverable from the new business service customers. If this is not possible, then the risk falls on the shareholder. (FEU Final Submission, p. 41)

The traditional natural gas utility does not operate free of risk. Even under cost of service regulation the utility may fail to earn its approved rate of return due to, for example, unforeseen market conditions or the utility's inability to contain costs. The Panel finds that a traditional gas distribution utility entering into a new regulated business activity bears a similar risk to that which it bears in its traditional business activities. If the market for the new business activity fails to meet the expectations under which the costs related to this activity were approved by the Commission, then the unrecovered costs are to be borne by the shareholder. Where the new activity results from the decision of the utility to enter into a competitive market (i.e. to compete for the market) it should be noted that, as discussed in Section 2.8.1, the costs of entering into this market may fall outside the regulatory compact and not accrue to the account of the new business customer.

2.6 Principles and Guidelines for Determining Appropriate Information Sharing

A traditional gas distribution utility (such as FEI) entering into a new business activity may have access to a considerable body of customer specific information. Competitive regulated or unregulated businesses may wish to access this information. The issue arises as to how the utility can or should share information: (a) within its own organization, (b) with Affiliated Regulated or Unregulated Businesses, and (c) with unrelated businesses. A variety of positions were taken on this issue. The Panel finds that information sharing should occur under the Principles and Guidelines outlined below.

Key Principles:

i) Customer specific information must be treated as required by the *Personal Information Protection Act* and, in addition, should only be released with the written consent of the customer.

ii) Customer information (aggregate or customer specific with written consent) should be made available to all Parties (Affiliated Regulated and Unregulated Businesses, separate classes of service, and competitors) on an equal basis.

iii) The control of information should not provide a competitive advantage.

Guidelines:

Consistent with the key principles, when deciding what information can be shared with: (i) anyone, including competitors; and (ii) a related utility; or (iii) a division of the utility; information sharing should be treated in accordance with the following guidelines:

- Subject to customer consent:
  - Information that is shared by the utility should be provided at a reasonable price reflecting market circumstances and, at a minimum, cover the cost of extracting and providing the information. All parties should pay the same price for the same or similar information;
  - Information provided from the traditional natural gas distribution utility to persons within the utility or a related utility dealing with AES or other New Initiatives should be available to all interested parties;
  - The following Code of Conduct principles from the RMDM report[20], which were developed for sharing information between regulated and Non-Regulated Businesses, have been adapted to include information sharing among Affiliated Regulated Businesses:
    - The regulated utility will not provide to the Non-Regulated Business or Affiliated Regulated Business any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning;
    - No regulated utility personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of the Non-Regulated Business or Affiliated Regulated Business;
    - No regulated company personnel will preferentially direct customers seeking competitively offered services to a Non-Regulated Business or Affiliated Regulated Business.

[20] RMDM Guidelines, pp. 26-7

Discussion and Commission Determination

As customer information possessed by a utility is considered to be valuable market intelligence, the issue of sharing this information becomes contentious. Questions arise concerning information sharing within a utility, between related regulated utilities, and between Regulated and Non-Regulated Affiliated Businesses.

The *Personal Information Protection Act* (SBC 2003, Chapter 63) sets out the general rules regarding: protection of personal information by organizations; collection, use and disclosure of personal information; and issues related to consent. Pursuant to this Act, "personal information" cannot be collected, used or disclosed without the prior informed consent of the individual to whom the information relates.

The Commission Panel finds that the information held by the traditional gas distribution utility is of potential value to a number of interested parties. It is in the public interest that the control of this information is not used to inhibit competition to the detriment of consumers. Customer information collected by the utility should be available on an equal access basis to all interested parties, and in a manner which is consistent with the provisions of the *Personal Information Protection Act.* The Panel requires that the Code of Conduct to be developed be consistent with these Principles and Guidelines.

2.7 Determining the Public Interest

There are numerous areas where the Commission must consider the following in making its decisions:

- British Columbia's Energy Objectives;
- The applicable requirements of the *Clean Energy Act;*
- Whether an activity incorporates adequate cost-effective demand side measures; and
- The interests of persons in British Columbia who receive or may receive service related to an activity.

Any decision of the Commission must also be consistent with the public interest.

FEU have requested the Commission find certain new business activities as "in the public interest" apart from cost considerations. They argue that this would allow for more efficient streamlined applications focused on economic considerations.

Commission Determination

The Commission Panel finds that determination of whether an application meets the "public interest test" is dependent on the circumstances existing at a particular point in time and is largely an evidence-driven process. Future Commission Panels must make their determination of whether the public interest test is met based on the specific facts contained in the evidence before them in a particular case. To find certain aspects of new business activities as "in the public interest", without the specific facts of an application, is not appropriate.

2.8 Other Issues

2.8.1 Regulatory Compact as it Applies to New Business Activities

In *ATCO*, the "regulatory compact" was explained as an economic and social arrangement which ensures that all customers have access to the utility at a fair price, nothing more. *ATCO* states:

> "[u]nder the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated..." (para. 63)

In their final submission, FEU state that the allocation of cost and risk under the regulatory compact is that customers are responsible for prudently incurred costs of providing utility service, and the shareholder is at risk for imprudently incurred costs. (FEU Final Submission, p. 40, para. 88)

Commission Determination

A utility entering into the general market place to participate in a new business activity, where the utility does not have an exclusive right or franchise for the activity, is making a business decision to "compete" for this business against other service providers. Costs related to entering into this market are therefore not governed by the regulatory compact. Once a project has been acquired that is found to require regulation, such as a District Energy Project, prudently incurred costs related to the specific project are properly subject to the regulatory compact.

In other words, costs related to competing "for the market" are not subject to the regulatory compact, although costs related to a regulated project "in the market" are properly treated within the regulatory compact concept. This does not preclude the recovery of costs of competing for the market, but it puts the onus on the utility to demonstrate a reasonable business case for the recovery of such costs, with any residual risk of cost recovery falling on the utility.

The Panel notes that for certain AES activities, there is no "right of exclusivity" with respect to participating in the activity. Other parties can and do participate in the market and are free to do so. The extent of a utility's "duty to serve" for such activities is generally limited to specific customers to whom the utility is contractually bound.

2.8.2 Use of the FortisBC Brand Name

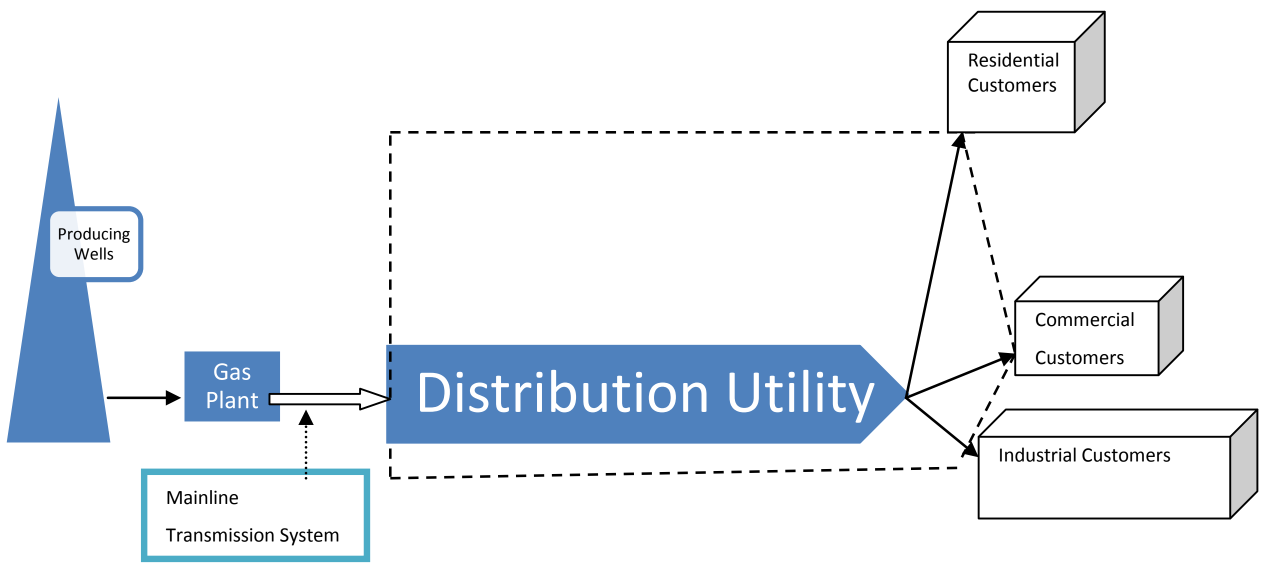
ESAC expresses a concern that use of the FortisBC "brand" has a "disproportionately large impact" in the emerging TES market. (Exhibit C 12-5, pp. 14-15) FEU's response is that the FortisBC name is used by the FEU under licence and reflects the reputation earned by FEU on how they deliver services. FEU point out that other market participants, like Corix, use their name and reputation to market multiple product lines to the broader public. (FEU Rebuttal Evidence, p. 15, para. 25)

Commission Determination

The Panel finds that the use of the FortisBC brand name in the AES and New Initiatives market spaces is an acceptable business practice. Care should be taken to distinguish between the services offered by the traditional natural gas utility and services offered by Affiliated Regulated or Non-Regulated Businesses.

SECTION 3 APPLICATION OF PRINCIPLES AND GUIDELINES TO FEU'S AES AND NEW INITIATIVES

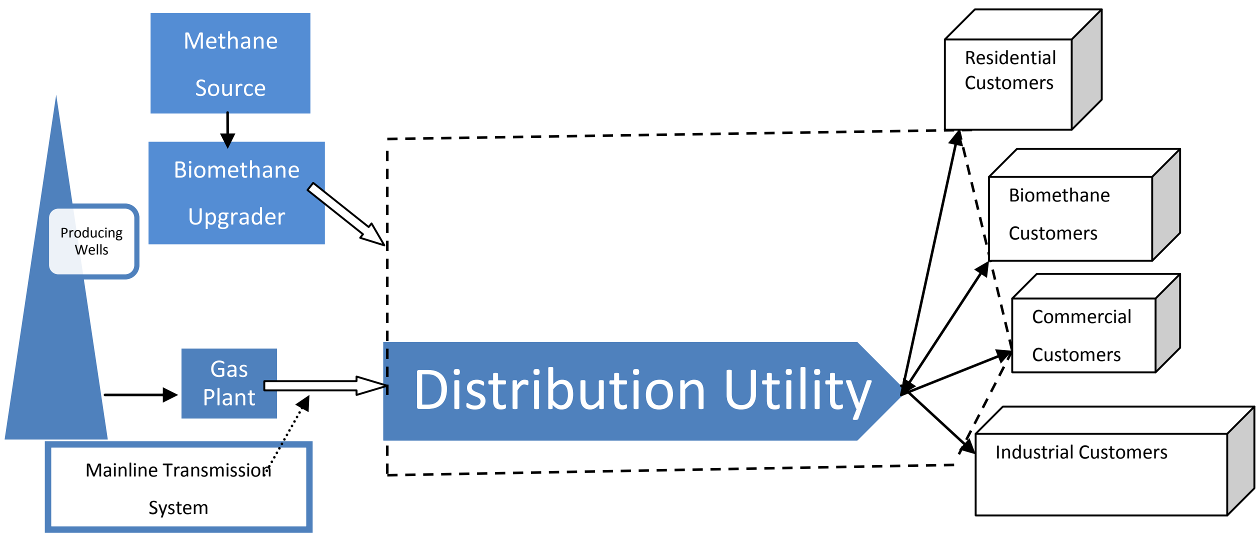
In looking at FEU's new business activities and assessing if and how they should be regulated it is useful to bear in mind the traditional gas distribution utility model as illustrated below. As each of the new business activities is discussed, a similar diagram is included to provide some perspective and clarity to the discussion.



Traditional Gas Distribution Utility Configuration

The traditional gas distribution utility is represented by the portion of the diagram above contained within the dotted lines, labelled as "Distribution Utility". In the traditional utility, gas is received from a provincial or interprovincial mainline transmission system (represented by the arrow from the gas plant to the distribution system). The distribution system consists of the interconnection facilities to the mainline, large diameter pipe moving the gas to various parts of the distribution system, and small diameter pipes taking the gas to specific customers. The traditional utility boundary at the delivery end is at the meter going to the individual customer.

3.2 Biomethane Service



3.2.1 Key Characteristics

As outlined in the diagram above, the introduction of biomethane is more closely related to the introduction of a new supply of fuel than it is to a new business activity. While the source of the fuel may differ, Biomethane Service (the distribution of biomethane to customers) utilizes the same distribution network as the existing natural gas supply and the biomethane product is available to the same set of customers. While the diagram shows biomethane customers as a separate customer group, the customers of this service are, for the most part, already connected to the system as part of the residential, commercial or industrial classes. As all gas going into the distribution system is commingled, the customer buying "biomethane" is simply paying a premium to bring a more environmentally friendly form of methane onto the system.

The part of the biomethane initiative that moves beyond the umbrella of the traditional natural gas distribution utility is the inclusion of assets upstream of the distribution utility (including the upgrader and pipe leading up to the interconnection point where gas is delivered into the traditional gas utility system).

3.2.2 Current Status of Activities

On June 8, 2010, FEI applied for approval to offer biomethane to customers and to undertake two initial biomethane projects, one in which FEI was to take delivery of biomethane that was already upgraded to pipeline specifications by a project partner, and one in which FEI was to take delivery of raw landfill biogas from the project partner. In the latter case, FEI was to own and operate the assets to upgrade and deliver the biogas to the traditional gas distribution utility.

On December 14, 2010, the Commission approved both projects.[21] The Commission ordered FEI to thoroughly test the proposed business in the marketplace over a two year period and to come to the Commission no later than December 2012 with a full review of the program. As well, a total cap of approximately double the anticipated production from the two approved projects was set to allow for additional projects, while containing the risk.

In the Biomethane Decision, costs were separated into two groups – those allocated to all customers and those allocated to biomethane customers.

Costs Allocated to All Customers	Costs Allocated to Biomethane Customers
• Costs for analyzing gas quality equipment; • Meters; • Transmission or distribution pipeline extensions to connect to the biomethane; • Any capital costs for application development and system modifications; • Costs associated with program management, customer education and additional call volume.	• All costs associated with the purchase and upgrading of biomethane; • Any direct administrative costs.

[21] Biomethane Decision and Order G-194-10

3.2.3 Key Issues

Cost and Risk Allocation

Because the project was only approved on a test basis and the costs were relatively small, the Commission did not undertake a detailed analysis in its determination of cost and risk allocation.

The Commission allowed much of the cost and risk to be borne by the traditional natural gas distribution utility customer and identified this issue as one that would need to be examined more carefully during the review process.

Identified risks included: operational and system, facilities cost, failure to supply biomethane, risk to the gas supply portfolio, and risk of obtaining sufficient customers for this service. Realization of any of these risks could potentially result in stranded assets.

Ownership of Upgrading Facilities

In the Biomethane Proceeding, the Commission made no finding on the acceptability of FEI performing the upgrading role but noted that the upgrading process does not have the significant upfront capital investment typical of a natural monopoly and may evolve into an industry with a number of small upgrading businesses. The Commission directed costs for upgrading to be segregated so as to be severable if it was determined that this business ought to be conducted through a separate entity in the future.

FEU's view is that when Biomethane projects are owned and operated by FEI, and interconnected with FEI's existing natural gas distribution system, they are "extensions" of its existing natural gas distribution system as that word is used in Section 45 of the *UCA*. (Exhibit B-17, p. 6)

FEU propose that upgrading facilities could be exempted from both Certificate of Public Convenience and Necessity (CPCN) and rate filing requirements on the basis that the purchaser of the biomethane will be FEI, whose supply contract for the biomethane will be subject to review and acceptance by the Commission regardless of whether the third-party upgrader is subject to, or exempt from, regulation. FEU submit there is precedent for this treatment in that Independent Power Producers that sell only to BC Hydro have been exempted from the operation of regulation under Part 3 of the *UCA* despite being "public utilities", but are not exempt to the extent that they otherwise sell to the public for compensation. (FEU Final Submission, pp. 97-98)

The Coalition for Renewable Natural Gas (CRNG):

> "question[s] the notion that existing safety and regulation concerns warrant action by FortisBC, considering there are sophisticated, competent, well financed, nimble, un-regulated, competitors active and able to deliver in this space, upstream of FortisBC's transmission or distribution 'pipelines.'... [CRNG also] question[s] the need for a regulated gas utility to collect, process, odorize, transport or meter gas prior to supply to off-transmission, or distribution pipeline, or 'discrete' customers, or injection into any transmission or distribution system for further transportation, or re-sale to its, or other customers." (CRNG Final Submission p. 2)

Biomethane Service

Need for Regulation

In Biomethane Service a different source of methane (biomethane) is brought onto the distribution system to supplement the traditional source of methane (natural gas). **Biomethane Service can therefore best be viewed as another source of supply for the regulated utility. As such, it is part of FEU's regulated service offering.**

Business Structure

Biomethane is distributed through the traditional utility infrastructure. As well, there is an identifiable set of customers who choose to take this service. This set of customers is a subset of the traditional utility ratepayers. The difference in this case is that the Biomethane Service customer chooses to take a higher cost source of methane because of the environmental attributes. To the extent that these customers pay for the higher cost of the product, no additional risk is imposed on the traditional utility ratepayers. For these reasons, **Biomethane Service is appropriately considered a Separate Class of Customer within the natural gas class of service.**

Cost Allocation

The Panel notes that detailed cost allocation decisions will require assessment of the specific facts in each situation and will be determined based on the evidence tendered at that time. The Panel recommends that such decisions should take into account the Principle and Guidelines on cost allocation set out in Section 2.4.

Biomethane Upgrading Facilities and Extensions to Connect to Facilities

Need for Regulation

Biogas upgrading facilities are analogous to gas plants that treat conventional "raw gas" to remove impurities and gas liquids to ensure the natural gas is of pipeline quality. Such plants are regulated under the *UCA*, but are not generally part of the traditional natural gas distribution utility. They are typically owned and operated by third parties, such as pipeline companies or producers. Also, because gas plants typically are owned by sophisticated parties who usually negotiate with other knowledgeable sophisticated parties (producers), they generally apply for and are granted an exemption from regulation by the Lieutenant Governor in Council, as allowed for in the *UCA.* There is currently no exemption in place for biogas upgrading facilities.

The Commission Panel is of the view that biogas upgraders are similar to provincial gas plants in function and are regulated under the *UCA*.

Form of Regulation

The Commission Panel finds that neither biomethane upgraders nor the pipe connecting them to the traditional distribution utility are extensions of the utility system as contemplated in subsections 45(1) and (2) of the *UCA.* These pipes are a connection to a new source of supply similar to connections to interprovincial pipelines.

Regarding upgraders, the Commission Panel will not make a blanket determination in this Proceeding and future Commission Panels will be required to assess the form of regulation to be imposed on biomethane upgraders, including the possibility of a subsection 88(3) exemption, taking into consideration factors such as the sophistication of the parties involved, the nature of the contract entered into with the utility, and whether there is a demonstrated track record in operating such facilities.

Regarding the pipe from the upgrader, these are capital additions for which there is no set test for economic feasibility. The Panel considers these additions should be reviewed on a case by case basis. The Panel reviewing the Biomethane Post Implementation Report relating to the existing Biomethane Pilot Project may wish to establish rules or parameters covering pipeline connections to upgraders.

CPCN Threshold

Submissions were sought on the CPCN threshold for biomethane activities. A $5 million CPCN threshold was set in the Biomethane Decision in 2010. FEU submit that the threshold should be maintained because there is low risk with these assets and a modest cost.

FEU also submit that biomethane supply agreements should be reviewed as filings under section 71 of the *UCA* and that this review will provide sufficient oversight because investment in upgrading and interconnection facilities will not occur without section 71 approval, at which time the Commission can decide to require a CPCN. (FEU Final Submission, pp. 91, 97)

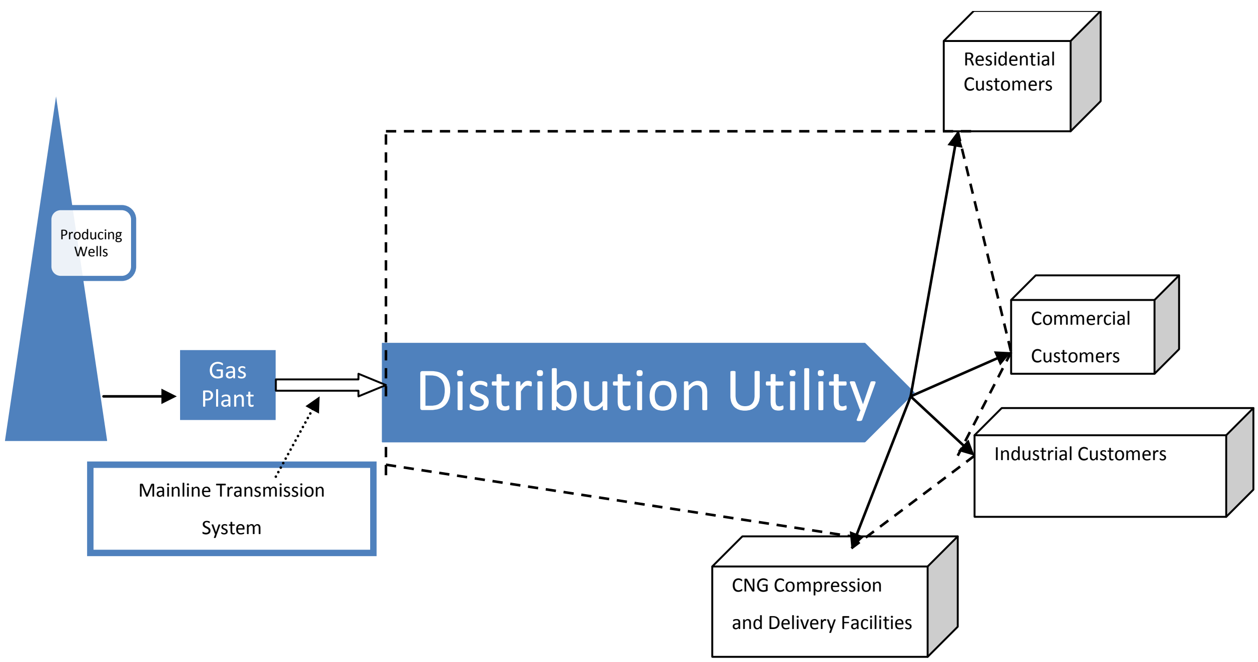
Clean Energy Fuels (Clean Energy), an Intervener in the proceeding, disagrees, and supports a zero threshold for the biomethane markets as these are not traditional markets for a utility.
(Exhibit 17-5, pp. 1-2)

The Panel recognizes that the Biomethane Post Implementation Report is due in December 2012 and considers that the appropriate CPCN threshold and regulatory review (i.e. supply agreements reviewed under s. 71 of the *UCA*) will be dealt with in that Review. **The Commission Panel reaffirms the $5 million CPCN threshold until that time.**

Ownership of Upgraders and Business Structure

With respect to FEU ownership of upgrader facilities, the Commission Panel, in keeping with the Extension of Ownership principle, recommends that the utility not own the upgrading facilities where there are viable options. A viable option is put forward by the FEU where biomethane is supplied from third parties and is regulated through filing supply contracts under section 71 of the *UCA*. In the case where FEU own the upgrader, the upgrader should be owned and operated in a Regulated Affiliated Business and biogas supplied to FEI under a section 71 contract.

3.3 CNG Service



Adding Compressed Natural Gas Service to the Traditional Utility Model

3.3.1 Key Characteristics

"CNG Service" is the compression and dispensing of natural gas through specialized fuelling stations. To create Compressed Natural Gas (CNG), natural gas is typically distributed through the traditional utility infrastructure to the fuelling station. At the station, the natural gas is compressed and dispensed at high pressure into a specialized vehicle's storage tank.

As illustrated in the diagram above, compressed natural gas facilities are similar to the addition of a new type of customer for the distributor.

3.3.2 Current Status of Activities

FEU previously owned CNG fuelling stations as a regulated service to the public for high-mileage light duty vehicles. This venture was not successful and FEU left the business in 1999.

Currently FEI has two main Rate Schedules under which it sells gas for use at CNG fuelling stations: Rate Schedules 6 and 26. As well, in 2012 FEU's General Terms and Conditions 12B (GT&C12B) were approved.[22] GT&C12B provide the conditions under which FEU can own and operate CNG fuelling stations for the compression and dispensing of CNG. FEU's foray into the natural gas vehicle market since GT&C12B were first proposed in 2011 has focused on commercial, return-to base fleets of buses and heavy duty trucks.

At this time, after a series of applications to the Commission, FEI is approved to provide CNG Service to Waste Management[23], to the general public from its Surrey Operations Centre[24], and to BFI Canada[25]. In the BFI Decision and the subsequent Reconsideration Decision, the Commission ordered CNG Service to be maintained as a Separate Class of Service within FEI.

There are also private companies providing CNG Refuelling Service. Clean Energy, an Intervener in this Proceeding, receives natural gas from FEI and compresses and dispenses CNG for customers in British Columbia. (Exhibit C17-2, pp. 2-4; T2: 206)

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[22] By Order G-14-12

[23] *In the Matter of An Application by FortisBC Energy Inc. for Approval of a Service Agreement for Compressed Natural Gas Service with Waste Management of Canada Corporation and General Terms and Conditions for Compressed Natural Gas and Liquefied Natural Gas Service*; Decision and Order G-128-11, July 19, 2011.

[24] *In the Matter of An Application by FortisBC Energy Inc. for Approval of a Compression Rate Schedule, Compression and Dispensing Rate Calculation and Resulting Effective Rate to Provide for Public Natural Gas Vehicle Refuelling at the Surrey Operations Centre;* Decision and Order G-165-11A.

[25] *In the Matter of An Application by FortisBC Energy Inc. for a Certificate of Public Convenience and Necessity for Constructing and Operating a Compressed Natural Gas Refueling Station at BFI Canada Inc.;* Decision and Order C-6-12. (BFI Decision*)*

UCA Definition of CNG Retail Distribution

The definition section of the *UCA* provides that the retail distribution of Liquefied Natural Gas (LNG) or CNG is only a "public utility" business if it is undertaken by a public utility. This result follows from the interaction of the definition of "public utility," which specifically does not include "...(e) a person not otherwise a public utility who is engaged in the petroleum industry..." and the definition of "petroleum industry," which "...includes the carrying on within British Columbia of [the business of] ...(e) the retail distribution of liquefied or compressed natural gas."

Greenhouse Gas Reduction (Clean Energy) Regulation

On May 15, 2012 the Government of British Columbia passed the Greenhouse Gas Reduction (Clean Energy) Regulation under section 18 of the *Clean Energy Act.* The regulation permits a public utility, as a "Prescribed Undertaking" to expend a total of $104.5 million over five years on:

- Grants or zero-interest loans to persons in British Columbia, for the purchase of "Eligible Vehicle[s]" operated in British Columbia. Eligible Vehicles are medium or heavy duty vehicles, transit or school buses or marine vehicles;
- Administration, marketing, training and education for activities under the Regulation;
- Construction/purchase and operation of one or more CNG fuelling stations, within the public utility's service area, for natural gas vehicles for transportation;
- Construction/purchase and operation of one or more tanker load out or fuelling station for LNG within BC for natural gas vehicles.

The regulation is repealed on April 1, 2017, and provides for sub-caps, within the overall $104.5 million cap, for each specific activity listed above, among others.

3.3.3 Key Issues

In examining FEU's CNG Service, the Commission also looked at LNG Service and made observations that relate to both. In its Decisions on CNG and LNG Service, the Commission raised concerns about cross-subsidization from the traditional natural gas distribution ratepayer to the CNG/LNG Service customer and about a regulated utility entering a competitive market.

Regarding CNG/LNG Service, the Commission has found:

- A CNG/LNG refuelling facility is not an extension of the distribution system;
- CNG/LNG fuelling infrastructure has no natural monopoly characteristics;
- It is not in public interest to provide FEI with a competitive advantage in this industry by allowing FEI to subsidize the costs of service with existing ratepayer funds;
- FEI must provide CNG/LNG Service without using any potential economic leverage it has as a public utility; and
- GHG emission reductions provide a justification for FEI's proposed NGV programs, [but] FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program.

The Commission raised concern about the risk of failure of this new business activity and who would bear the cost of such failure. Regarding cost allocation, the Commission raised concerns that costs were not properly allocated and that a cost of service model is not necessarily appropriate where FEI is proposing to enter a competitive market as a regulated entity.

The Commission has noted that if this activity were being undertaken by a person other than an existing public utility it would not be subject to regulation at all.

In its Decision on the Surrey Operations Centre, the Commission expressed concern that FEI was proposing to enter an otherwise unregulated, competitive market with a product priced considerably below the market price, which also failed to recognize/recover a number of costs.

FEU's position is that CNG Service will result in higher demand for natural gas flowing through the system and, if this new volume can be delivered without significant costs incurred to provide new facilities, this will result in lower delivery rates for all ratepayers, other things being equal, given the current rate design. In the NGV EEC Decision, the Commission found that "long term benefits to existing customers from increased throughput on the delivery system [had] not been established."[26] The Commission has also noted that, to the extent there is a benefit to FEU's ratepayers from increased throughput, such benefit does not flow from FEU's involvement, and if a third party were involved instead, the same claimed benefit would follow. (BFI Decision, p. 11)

Commission Determination

Need for Regulation

In the Panel's view, the construction of a CNG dispensing facility, downstream of the natural gas meter, does not constitute an extension of the monopoly distribution system for natural gas. As noted by previous Commission Panels, if this form of activity were being undertaken by a person other than an existing public utility it would not be subject to regulation at all. This is because it is only by definition under the *UCA* that CNG Service undertaken by a public utility is also a public utility function.

CNG Service

Business Structure

CNG activities done under the Prescribed Undertaking should be structured as a separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit. The Greenhouse Gas Reduction Regulation indicates that the Government supports traditional utility ratepayers providing limited incentives and other funding for certain prescribed CNG activities, in certain limited circumstances, and for a limited period of time, presumably to "kick start" the natural gas for transportation market. The Panel notes that the monetary and temporal limits placed on the Prescribed Undertaking activities are maximum limits and, in the Panel's view, these limits represent the maximum subsidization which ratepayers should be required to provide. In the Commission Panel's view, it is crucial that, except to the extent required by legislation, there be no cross-subsidization as between existing ratepayers and CNG Service customers. A record of the costs for CNG Service as a Prescribed Undertaking should

[26] *In the Matter of An Application by Terasen Energy Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review*; Decision and Order G-145-11, August 15, 2011.

be separate from those costs for CNG Service other than under the Prescribed Undertaking to ensure that proper cost reporting can occur.

The Panel notes that the BFI CNG station is ordered to be in a Separate Class of Service. The Waste Management CNG Station was approved within the existing natural gas class of service, subject to the conditions contained in its approval. While the Panel believes it would be appropriate to have the Waste Management CNG Station within the CNG Class of Service, this report is a forward looking document and does not apply to previous decisions, unless specific issues were referred to this Inquiry. The Panel does not see this report as directing any change to the BFI or Waste Management Decisions.

Future panels may wish to consider whether the CNG market has, in fact, been kick started and whether projects in this Class of Service should be transferred to a Non-Regulated Business.

For CNG activities outside the Prescribed Undertaking, the Panel finds that the best protection against cross subsidization and the least impediment to the existence of a competitive market is to have all parties participating in the market do so as unregulated, non-utility entities. While the *UCA* sets out that the retail distribution of CNG, when done by a public utility, is a public utility enterprise and subject to regulation, the Commission has also determined, in Section 2.1 of this Decision, that it has the jurisdiction to control a utility's entry into a particular market, where necessary.

The Panel recommends that for proposed CNG projects other than Prescribed Undertakings, FEU should pursue such projects through a Non-Regulated Business. The Panel notes that a business engaged in the "petroleum industry" (which includes the retail distribution of CNG) is not a "public utility" under the *UCA*, (unless such CNG Service is being provided by an existing public utility), and views this definition as contemplating the existence of a number of unregulated participants in the industry. An existing public utility (with its market power) is required to seek Commission approval through the CPCN process before entering this potentially competitive arena. In the Panel's view, a functioning, competitive CNG market, which is desirable, is more likely to be developed with the participation of multiple parties than with a single monopoly player. The Panel is of the further view that the existence of a single dominant player could, in fact, be detrimental to the development of this market, as potential competitors believe the playing field to be uneven and decline to participate. Accordingly, in the Panel's view, the CNG market is most likely to be successfully developed if FEU create an NRB to pursue CNG projects. If FEU do not use an NRB then they are required to file a CPCN prior to the construction or operation of any CNG facilities. Future Commission Panels in such instances would then have to consider whether it is in the public interest to accept any such proposed project and grant a CPCN given the state of the market and whether there is a need for consumer protection. The Panel also notes that, for CNG projects other than Prescribed Undertakings, future Commission Panels also have the ability to deny cost recovery for CNG projects from traditional gas utility customers.

CPCN Threshold

FEU submit that in light of the approval of GT&C 12B[27], the Commission should reinstate the $5 million CPCN threshold for FEU's investments in CNG/LNG Fueling Service stations (FEU Final Submission, pp. 84-85).

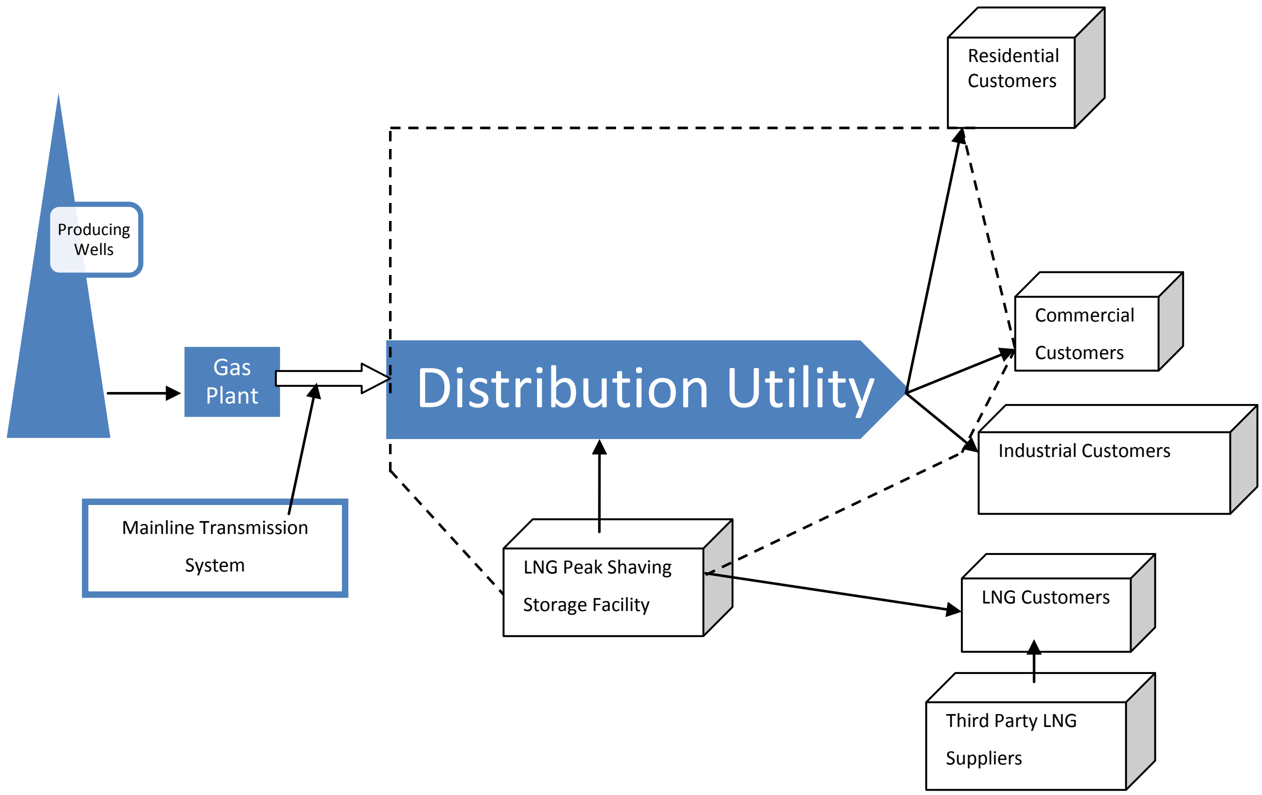
Intervener views were varied on the subject. While CEC supports the $5 million threshold, British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO), Ferus LNG and Clean Energy do not. BCPSO suggests a lower threshold to provide sufficient oversight of an unproven line of business and Clean Energy supports a zero threshold for the CNG/LNG as these are not traditional markets for a utility. (CEC Final Submission, p. 26; BCPSO Final Submission, pp. 19-20; Exhibit C8-10, p. 2; Exhibit 17-5, pp. 1-2)

The Panel determines that for CNG Service as Prescribed Undertakings no CPCN is required. For all other FEU CNG Services, a CPCN is required. The Panel agrees with Ferus LNG and Clean Energy Fuels that, at this stage, while the market is being developed in BC, it would be useful to have a transparent process for any additional utility activities occurring beyond the ambit of the Prescribed Undertaking, and, accordingly, maintains the CPCN threshold at zero. As this market

[27] By Order G-14-12

is otherwise not regulated, as discussed above, there is no CPCN requirement for participants which are not "otherwise public utilities."

3.4 LNG Service



Adding LNG Services to a Traditional Gas Utility Model

3.4.1 Key Characteristics

LNG is natural gas which has been cooled to - 160 degrees Celsius, such that it condenses to a liquid state, significantly increasing the density of the fuel. LNG must be maintained at or below this temperature to remain liquid. To produce or liquefy LNG, natural gas is piped to a liquefaction facility where the cooling occurs. LNG must then be stored in an insulated tank. LNG supply in the storage tank can be re-gasified for injection back into the traditional natural gas distribution system or shipped in liquid form in a tank by truck, rail or ship. For natural gas vehicles, LNG is dispensed through a fuelling station as a liquid into the vehicle. "LNG Service" is the onsite storage and dispensing of LNG through specialized fuelling stations. The LNG supply for a fuelling station is usually produced in a central liquefaction facility, transported by tanker truck, and stored on site.

3.4.2 Current Status of Activities

The FEU have two liquefaction facilities. These facilities were approved by the Commission for peak shaving and emergency back-up supply for the traditional natural gas utility ratepayers. For these same purposes, FEU own two tanker trailers.

Recently, FEU have begun involvement in selling LNG for transportation and have also been exploring the use of LNG as a replacement fuel for power generation. FEI is approved to provide a limited amount of excess LNG under Rate Schedule 16 which is used primarily for natural gas vehicles. The terms and conditions under which it can own and operate fuelling stations and dispense LNG are currently set out in General Terms and Conditions 12B.

Peak Shaving Supply Facilities

LNG liquefaction and storage facilities are maintained as part of the traditional gas distribution utility to provide a source of peaking supply for periods of high demand, and to provide emergency gas supplies to a part of the distribution system when a disruption occurs due to maintenance or an unplanned outage. As this supply source is necessary and integral to the ability of the natural gas distribution utility to serve its core customers, these LNG facilities are included in rate base and form part of the utility's regulated function. LNG is added back into the distribution system either at the LNG plant itself, after being returned to a gaseous state, or, as noted above, it can be transported by tanker, in its liquid form, to another injection site on the system.

FEU's two liquefaction facilities were constructed pursuant to CPCNs to provide peak shaving capability and emergency back-up supply to serve the traditional natural gas distribution utility ratepayer. The first facility is located at Tilbury, in the Lower Mainland, the other at Mt. Hayes on Vancouver Island.

These facilities are operated to fill the tanks in periods of low demand so the tanks are full by November, the start of the peak demand season. The Tilbury liquefaction facility has a storage capacity of approximately 606,500 GJs and a LNG liquefaction capacity of 5,110 GJs/day. It takes approximately 133 days (or almost 4.5 months) to fill the tank at Tilbury, and four days to empty it into the system in a gaseous form. The Mt. Hayes LNG facility has a storage capacity of approximately 1.6 million GJs and a liquefaction rate of approximately 8,200 GJs per day, such that it takes close to 200 days (or over 6.5 months) to fill the storage tank and 10 days to empty it.

Tanker Trailers

The FEU currently own two tanker trailers which are used to transport LNG to customers. However, their primary function, and the reason for their inclusion in the monopoly distribution utility rate base, is to transport backup supply to the system during emergency outages or scheduled work.

Fuelling Stations and General Terms and Conditions 12B

GT&C12B provides the terms and conditions under which FEU can own and operate fuelling stations.

GT&C12B defines LNG Service as the storage and dispensing of LNG and provides that LNG Service typically consists of transport and delivery of LNG from FEU’s peak shaving plants, installing and maintaining an LNG fuelling station, and dispensing LNG.

GT&C12B also sets out the terms and conditions under which the FEU will own the fuelling stations. In addition, it sets out various terms of service including a “take-or-pay” provision (customers have a minimum contract demand), and the costs to be included in the cost of service calculation for the fuelling station.

FEI purchased a mobile LNG refuelling station in December 2011. The Commission denied inclusion of the asset in rate base because it would require the cost of the station to be borne by traditional gas ratepayers.[28]

In 2012, the Commission approved FEI under GT&C12B to own, construct and operate a refuelling station on Vedder Transport Ltd.'s property.[29]

FEI Rate Schedule 16

LNG is sold or dispensed from Tilbury under Rate Schedule 16 (RS 16). RS 16 was approved by the Commission in 2009 as a five year pilot and allows for interruptible service, to preserve supply for the traditional utility ratepayers. The maximum quantity of LNG for sale under RS 16 is currently 1,040 GJ (which is equivalent to one tanker load) per day, or 379,600 GJs per year and any single customer may only take 50 percent of the available LNG capacity in one month. FEI has three commercial customers who take LNG Service under RS 16. Currently there is an application for a permanent RS 16 with increased quantity and firm supply before the Commission. (Appendix A to Order G-145-11, p. 15; Terasen Gas Inc. Application for Rate Schedule 16, pp. 4, 18)

Competitive LNG Market

Ferus LNG advises that it has immediate plans to produce, store, transport, and provide fuelling services for LNG. It also submits evidence of other providers including Clean Energy, EnCana, and Shell who intend to enter the BC LNG market. (Exhibit C8-5-1, pp. 5-7)

***UCA* Definition of LNG Retail Distribution**

As with CNG, the definition of "public utility" in the *UCA* provides that it is only where an entity engaged in the "petroleum industry" (which includes the retail distribution of liquefied or compressed natural gas) is "otherwise a public utility" that the business of the retail distribution of LNG meets the definition of public utility.

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[28] 2012-2013 RRA Decision

[29] *In the Matter of An Application by FortisBC Energy Inc. for a Certificate of Public Convenience and Necessity for Constructing and Operating a Liquefied Natural Gas Refueling Station at Vedder Transport,* Order C-11-12.

Greenhouse Gas Reduction (Clean Energy) Regulation

The Greenhouse Gas Reduction Regulation, described in the CNG section, also provides for a public utility's expenditures for LNG facilities and services, specifically for vehicle grants and zero-interest loans and for construction/purchase and operation of one or more tanker load out facilities or fuelling stations for LNG within BC for natural gas vehicles. Of note is that while the CNG fuelling stations are required to be within the service territory of the public utility, the LNG load-outs or fuelling stations are not subject to this restriction and are not required to be in the public utility's service area.

3.4.3 Key Issues

As noted in the CNG Section, the Commission has raised concerns about cross-subsidization and whether a regulated utility should be entering a potentially competitive market, as well as the business risks related to CNG/LNG which significantly differ from those of the traditional utility.

The risk of cross-subsidization for LNG Service is even more acute than for CNG because the liquefaction process requires extensive capital-intensive infrastructure. In the case of FEU, the Tilbury and Mt. Hayes facilities and the two LNG tankers were (or will be) paid for by the traditional utility ratepayers. LNG Service has three additional considerations beyond those relating to CNG Service. These are:

- the use of excess capacity of LNG supply from the Peak Shaving facilities;
- the use of FEU's two LNG tankers for the natural gas vehicle market; and
- the benefits of LNG sales to the traditional natural gas distribution utility ratepayers.

Commission Determination

Need for Regulation

Based on the evidence in the Inquiry, the Commission Panel considers that LNG production, transportation, and retail distribution are, or are anticipated to become, competitive markets. As per the Guidelines in Section 2, new business activities are regulated when there are sufficient natural monopoly characteristics to warrant regulation or when legislation requires regulation, and should not impede competitive markets. Like CNG, the retail distribution of LNG is considered to be part of the petroleum industry in the *UCA* and, unless the person engaged in the retail distribution of LNG is "otherwise a public utility", this activity falls outside the definition of public utility and is not subject to regulation. Therefore, LNG Services are regulated if they are undertaken by a public utility, but are not regulated otherwise.

As with CNG, the Commission Panel notes that the Greenhouse Gas Reduction Regulation provides for certain limited expenditures to promote the use of LNG for transportation to be recovered from the traditional utility ratepayer. The Panel therefore sees LNG services under the Regulation (as a Prescribed Undertaking) as different from those outside the Regulation.

LNG Activities Other Than Prescribed Undertakings

Business Structure

The Panel finds that the best protection against cross-subsidization and the least impediment to the competitive market is to have all industry participants do so as unregulated, non-utility entities. While the *UCA* sets out that LNG retail distribution when done by a public utility is regulated, the Commission has also determined, in Section 2.1 of this Decision, that it has the jurisdiction to control a regulated entity's entry into a particular market, where necessary.

In the case of LNG activities, other than for a Prescribed Undertaking, the Commission recommends that that if FEU wish to participate in this market, they do so through a separate Non-Regulated Business. The Commission Panel considers that the public interest will be best served by ensuring that all participants in the nascent LNG market (other than utility participants doing so as Prescribed Undertakings) be non-regulated entities so the existence of a dominant player and the additional costs which flow from regulation do not impede the competitive market. The Panel further finds that public interest considerations in respect of LNG include protection of the traditional natural gas distribution customers from excessive rates that may result from cross-subsidization and from taking business risks which ought to be borne by participants in a competitive market. The potential risks from LNG Service are exacerbated by the large capital investment required for LNG infrastructure.

Although FEU urge consideration of the benefit of LNG Service to the traditional gas utility ratepayer, the Commission Panel finds that a benefit to those ratepayers may not be present. LNG can be sourced anywhere, subject to price and transportation costs. The connection to the traditional natural gas distribution franchise ends at the nozzle of the LNG facility producing the product. If another LNG producer or FEU themselves build an LNG production facility connected to a mainline transmission system to meet the needs of LNG transportation customers, there would be no use of the traditional natural gas distribution system and no benefit to the traditional natural gas distribution customer. The Panel notes that the Greenhouse Gas Reduction Regulation contemplates funding for CNG Service within the utility franchise area. In contrast, funding can be applied to LNG Service anywhere within the province.

In all cases, if FEU have excess capacity to supply LNG and/or tanker service, the FEU should supply that LNG at the higher of the market price or the fully allocated cost of service. This upholds the guideline that "[a]n approved Code of Conduct and Transfer Pricing Policy should govern interactions between the Regulated Business and any Unregulated Affiliated Business and should include the following features:

- minimal sharing of resources – at the level of corporate services only; and
- use of the full cost to provide the service or market pricing, whichever is higher.

LNG Activities as a Prescribed Undertaking

Business Structure

LNG Activities which are done as a Prescribed Undertaking under the Greenhouse Gas Reduction Regulation are to be maintained as a Separate Class of Service with the costs recoverable from the traditional gas utility ratepayers, to the prescribed limit. In the Panel's view, the Regulation was put in place by Government to kick start the natural gas for transportation market. The Regulation allows for the subsidization by the traditional natural gas utility ratepayer of specific activities to support this market to a maximum amount for a period of approximately five years. The benefit of a Separate Class of Service is that it segregates and accounts for costs related to LNG activities in a transparent manner. This Class of Service does not preclude the utility from recovering its costs incurred with respect to the Prescribed Undertaking from the traditional utility ratepayer, as required by the Regulation.

Future panels may wish to consider whether the LNG market has, in fact, been kick started and whether projects in this Class of Service should be transferred to a Non-Regulated Business.

CPCN Threshold

No CPCN requirement exists for LNG activities undertaken within the Prescribed Undertaking or by non-utility providers of LNG refuelling services. While the Commission strongly recommends that any LNG activities outside the Prescribed Undertaking be undertaken by an NRB, if the FEU wish to apply to undertake LNG activities within the utility, the CPCN threshold is maintained at zero, for the reasons set out in section 3.3.

General Terms and Conditions 12B

FEU should file an application with the Commission to revise GT&C 12B to reflect the provisions of the Greenhouse Gas Reduction Regulation and the findings of this Report.

3.5 Thermal Energy Services

3.5.1 Current Status of Activities

Prior to 2010, FEI undertook AES projects through its non-regulated subsidiary Fortis Alternative Energy Services Inc. (FAES). FAES is an affiliate of FEI, with no employees, and relies on FEI and FEI's parent company, Fortis Holdings Inc., to provide all resources for the services it provides. (PCI Marine Decision, pp. 3, 52-3)

In 2009, as part of FEI's Revenue Requirements Negotiated Settlement[30], General Terms and Conditions 12A were approved. GT&C12A sets out the conditions under which FEI would provide alternative energy extensions. These alternative energy technologies were specified as geo exchange, solar-thermal and district energy systems. GT&C12A also sets out that the utility would own these systems and that the cost of service model would be used to determine any rate charged.

In that negotiated settlement FEI was approved to undertake AES services as a Separate Class of Service within the utility under GT&C12A and to create the Thermal Energy Services Deferral Account, or TESDA, to allocate costs between the traditional utility ratepayer and the new AES Class of Service.[31] In this Proceeding, FEU renamed AES to TES because, in part, there are more technologies than the three originally contemplated in GT&C12A.

In this Decision "AES" is defined as geo-exchange, solar-thermal and district energy systems, as specified in FEI's tariff General Terms and Conditions 12A and FEI's 2010/2011 Revenue Requirement Negotiated Settlement Agreement while "TES" includes AES but also covers a broader range of technologies and activities.

Also in this Proceeding, FEU have used the term "Discrete Energy Systems", and there has been significant debate on whether a useful distinction can be made between this term and District Energy Systems, for the purposes of regulation. Most Interveners have not recognized a distinction between the two terms in their evidence, and have instead referred to an overall thermal class of service. As a result, much of the discussion in this section relates to thermal services in general.

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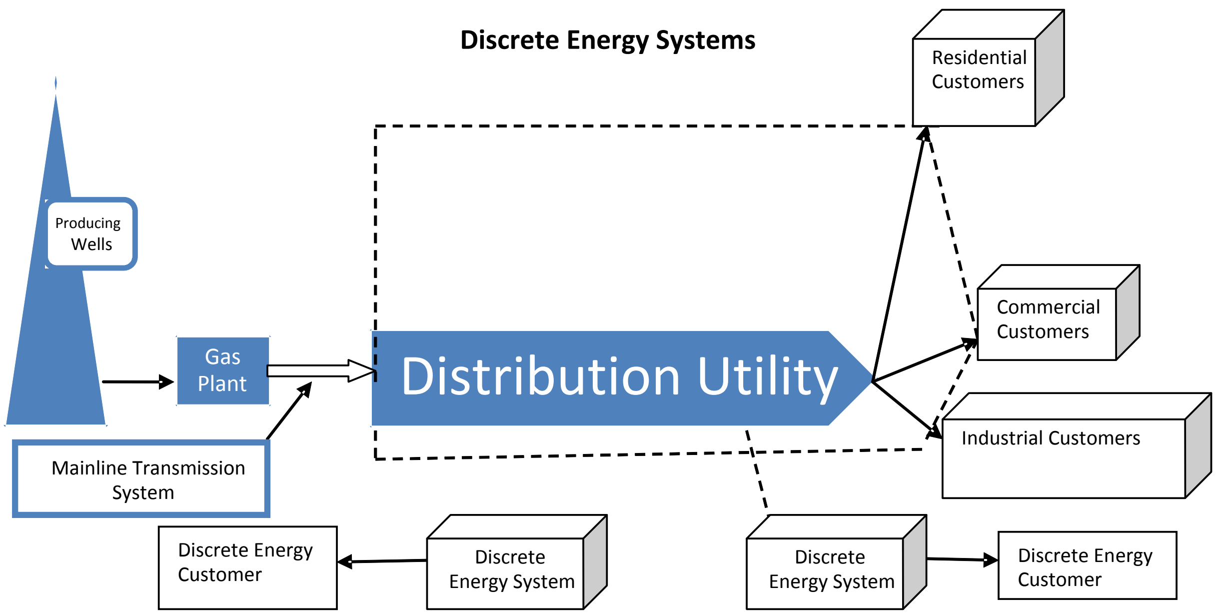
[30] *In the Matter of An Application by Terasen Gas Inc. for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates;* Order G-141-09, November 26, 2009.

[31] *Ibid*

In the Delta School District Decision,[32] the Panel found there are sufficient differences between Discrete and District Energy Systems to justify consideration of these system types separately and this Report will follow suit.

This Section of the Report defines Discrete and District Energy Systems, considers the need to regulate each type and, if so, the best form of regulation. As well, this Section discusses the appropriate business structure and cost and risk allocation for a regulated utility undertaking TES.

3.5.2 Discrete Energy Systems



Introduction of Discrete Energy Systems to a Traditional Distribution Utility Model

[32] Delta School District Decision, Appendix D, p. 2

3.5.2.1 Key Characteristics

A Discrete Energy System, such as a geothermal ground loop, is connected to a single customer. There may or may not be a connection to the gas utility to provide backup or supplementary energy (as illustrated by the system connected to the utility by the dashed arrow). Potential sources of thermal energy include solar, biomass, air source heat pumps, ground source heat pumps, geo-exchange systems, electrical heat, fuel cell heat, waste heat systems, and high efficiency gas boilers. A Discrete Energy project may entail the supply of equipment or facilities alone, energy alone, or all of the equipment, facilities and energy.

The Panel finds that a “typical” Discrete Energy System has the following characteristics:

- a stand-alone system, beyond the traditional utility meter;
- a single customer;
- no shared or common facilities beyond the boundaries of a single site. If there is a distribution system, it serves one or more buildings within a site;
- no use of public rights of way or streets;
- a system sized to meet the energy demands of a specific, known user;
- use of a range of possible technologies and energy sources.

These characteristics potentially allow the single customer to choose to own the assets, which is more difficult where an energy system serves multiple customers.

ESAC describes discrete energy projects as being “fundamentally private commercial transactions” where “a single customer is served in a private commercial transaction. The customer has available to it a range of competitive options in equipment and facilities and may choose from a variety of suppliers.” (ESAC Final Submission, pp. 4, 20)

3.5.2.2 Current Status of Activities

As of the date of this Report, the Commission has dealt with Discrete Energy System issues in three recent applications and subsequent orders, namely the Delta School District Decision,[33] the Tsawwassen Springs Decision,[34] and the PCI Marine-Gateway Decision.[35]

Delta School District

In the Delta School District Decision, FEI was awarded a CPCN and a rate was approved for public utility service to provide thermal energy to the Delta School District. The project involved the replacement of conventional boilers with high efficiency condensing boilers at eight sites, the conversion of existing thermal plants to geo-exchange systems at 11 sites, and the retrofit/replacement of existing mechanical infrastructure at all 19 sites to accept the new technologies.

FEI sought to provide this thermal service to the Delta School District under GT&C12A. However, the thermal service involved both ground source heat pumps in combination with high-efficiency boilers and stand-alone gas boilers. The Commission deferred a decision on the inclusion of stand-alone natural gas boilers in GT&C 12A to this AES Inquiry. GT&C12A was also declared interim.[36]

The Commission directed that the thermal services be provided to the Delta School District by a separate business entity. FEI was further directed to develop a consistent cost allocation methodology and to follow its Transfer Pricing Policy, if applicable, to allocate appropriate costs to Delta School District thermal services.

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[33] Delta School District Decision, Order G-31-12, March 9, 2011

[34] *In the Matter of An Application by FortisBC Energy Inc. For Approval of a Capital Expenditure Schedule, Rate Design and Rates for an Operating and Maintenance Agreement to Provide Thermal Energy Services Between FortisBC Energy Inc. and the Strata Corporation of Tsawwassen Springs Development*, Decision and Order G-100-12, July 20, 2012 (Tsawwassen Springs Decision)

[35] *In the Matter of An application by FortisBC Alternative Energy Services Inc. for a Certificate of Public Convenience and Necessity for the PCI Marine Gateway Thermal Energy Project and Approval of Rates for Thermal Energy Service to PCI Developments Inc.;* Decision and Order C-10-12, September 27, 2012 (PCI Marine Decision)

[36] By Commission Order G-223-11.

Tsawwassen Springs

In the Tsawwassen Springs Proceeding, FEI applied to purchase four loop field systems which are key components of a ground source heat pump system. The systems to be purchased were originally constructed by the developer of the Tsawwassen Springs Project to serve a single strata condominium development. The Strata retains ownership of all other components of the energy system, including backup and peaking boilers. The agreement between FEI and the Strata Corporation (originally executed between FEI and the developer of the Tsawwassen Springs Project and subsequently assigned to the Strata Corporation) was for FEI to own the loop field systems and provide thermal energy services at a fixed rate. The Commission approved the purchase but denied the proposed rate and rate design. The Commission identified a number of shortcomings with the cost of service model and rate design, including the use of the TESDA as a variance account and an insufficient contribution by the Tsawwassen Springs Project to the reduction of the TESDA. Any costs for the provision of thermal energy to Tsawwassen Springs were directed to be removed from the TESDA and borne by the shareholder. FEI was also directed to assign the Tsawwassen Springs Development to a separate affiliate.

FEI subsequently assigned both the Delta School District and Tsawwassen Springs Projects to FAES.

3.5.2.3 Key Issues

Since FEU have entered into the AES business, issues relating to cross-subsidization by the traditional gas utility ratepayers have been raised. Other key issues include:

- The nature of the discrete thermal services market;
- Whether the Projects should be considered regulated activities;
- The need to regulate contracts negotiated in good faith by two sophisticated parties;
- The need to regulate in cases where parties seek regulatory protection under the *UCA;*
- The appropriate pricing methodology, namely, whether it is appropriate to use full cost of service rate of return regulation where market based pricing is available, and the implications for the balance of risk and reward between the thermal ratepayer and FAES;
- The appropriateness of the economic test in and use of GT&C12A for FEI’s TES projects;

- The appropriateness of the current Transfer Pricing Policy for transactions between FEI and FAES;
- The fair allocation of the TESDA;
- What costs are appropriately shared among TES ratepayers taking service from different systems;
- The degree of alignment between the interests of the developer and the final customer where service agreement contracts are signed by developers, and then assigned to the final customer.

In the Tsawwassen Springs Decision, the Commission also noted the importance of each project recovering its associated costs only from its own customer base to the proper operation of the market in a regulated, non-natural monopoly environment, thereby attempting to ensure that customers are faced with prices which promote efficient investment decisions.

FEI/FAES have proposed the use of a modified Transfer Pricing Policy as the basis for cross-charges between FEI and FAES (which excludes an allocation of FEI's overhead and facilities fee). As noted earlier, FAES is not a standalone entity and relies wholly on intercompany transfers to function. The Commission expressed concerns about the appropriateness of the modified Transfer Pricing Policy for cross-charges between FEI and FAES in the Delta School District Project Compliance Filing[37]. The Commission noted that the current, fully integrated, business structure requires a great deal of diligence to prevent cross-subsidization.

Commission Determination

Need for Regulation

FEU submit that TES is a regulated public utility service, irrespective of the provider of the thermal energy and whether it is a Discrete or District Energy System because these systems meet the definition of "public utility" in the *UCA*. (FEU Final Submission, pp. 48-49)

[37] Reasons for Decision attached to Order G-71-12, p. 4

FEU acknowledge that TES is not regulated in any other jurisdiction in Canada or the USA, but argue that the B.C. legislation is different, and that, under the *UCA*, all thermal activities are properly regulated. (Exhibit B-2, p. 126)

Beyond meeting the legal definition of a public utility, FEU argue that regulation of thermal services is also appropriate:

> "because TES are generally complex and costly to operate and maintain, and once installed, the owner or operator has a measure of monopoly power over the customers because there will only be one thermal energy services provider within a certain area, and it is also costly to switch to another energy source. As a result, the customers of these systems have a strong interest in having recourse to a regulator who can ensure just and reasonable rates for the service, and ensure that the service provided is reasonable, safe, adequate and fair." (Exhibit B-2, p. 113)

Dr. Jaccard's opinion is that TES in British Columbia does not have the characteristics of a natural monopoly (there are no large initial capital costs creating barriers to entry and no franchise agreements granting the exclusive or near-exclusive right to serve in an area). Rather, his view is that the market is competitive for the right to construct TES projects in the first instance, but that when TES results in the creation of a public utility, regulation is appropriate. (Exhibit C12-5, pp. 11-12)

The issue of customer protection was raised by ESAC and BCPSO. BCPSO's view is that TES should be subject to full regulation because it is an emerging market and there is no real-time competitive market for customers to resort to if their situations are untenable. (BCPSO Final Submission, pp. 16, 18) ESAC submits that Discrete and District Energy Systems are different in that District Systems have multiple customers who are vulnerable to the actions of the project's owner and therefore warrant regulation. (ESAC Final Submission, p. 26)

In the case of Discrete Energy Systems with a single customer, the Commission Panel finds that the *UCA* requires regulation of these Systems. Despite this legal requirement, the Commission Panel's opinion is that there are not sufficient monopoly characteristics or a sufficient need for consumer protection for these systems to warrant regulation. The customer has the opportunity to purchase such a system or to have one of a number of service providers install, own and operate such a system exclusively for the use of the customer. If not satisfied with the offering of a specific service provider, the customer is free to choose an alternative supplier. The magnitude of the purchase or the contractual terms with the service provider may inhibit switching away from the service once it is implemented. However, this is no different than many types of purchases, none of which are regulated.

As well, the Panel finds there is a competitive market for the provision of these systems (indicating there is no need for a monopoly provider), and as noted in Section 2.2, competitive forces are accepted as providing societal benefits more efficiently and effectively than economic regulation.

The Commission Panel finds that economic regulation of Discrete Energy Systems is not warranted given the lack of natural monopoly characteristics and the lack of a need for consumer protection in light of the presence of a functioning competitive marketplace. In the Commission Panel's view, when the *UCA* was drafted this type of activity was not contemplated. The Panel recommends that when the *UCA* is next reviewed it should be amended to allow the Commission to forebear from regulating where it finds there is no natural monopoly or need for consumer protection.

The Panel recommends that until such time as the *UCA* is amended, an exemption from regulation pursuant to subsection 88(3) of the *UCA* be considered for Discrete Energy Systems with no natural monopoly characteristics or need for consumer protection. The Panel finds that where such exemptions are granted, it would be appropriate for FEU to pursue the construction and/or operation of Discrete Energy Systems through a stand-alone Non-Regulated Business that is separate from the traditional gas distribution utility. Consistent with the principles contained in Section 2.4, any sharing of utility resources must be consistent with an approved Code of Conduct and Transfer Pricing Policy.

CPCN Thresholds

Prior to exemptions being made as contemplated by the *UCA*, or a revision to the *UCA*, a CPCN threshold for TES projects must be considered. FEU recommend a $5 million threshold to reflect the small scale of the operations. FEU argue that this threshold is appropriate because the Commission has the ability to approve TES rates and service agreements and the ability to require the FEU to seek a CPCN for a particular TES project in appropriate circumstances. FEU take the position that the alternatives analysis typically included with a CPCN application is less important where the customer has chosen the FEU's cost of service model and has agreed to the terms and conditions of service. (FEU Final Submission, pp. 47, 55-56)

The CEC supports a $5 million threshold but allows for the possibility of different thresholds for other regulated providers depending upon the circumstances and the experience the Commission has with the provider. (CEC Final Submission, p. 21)

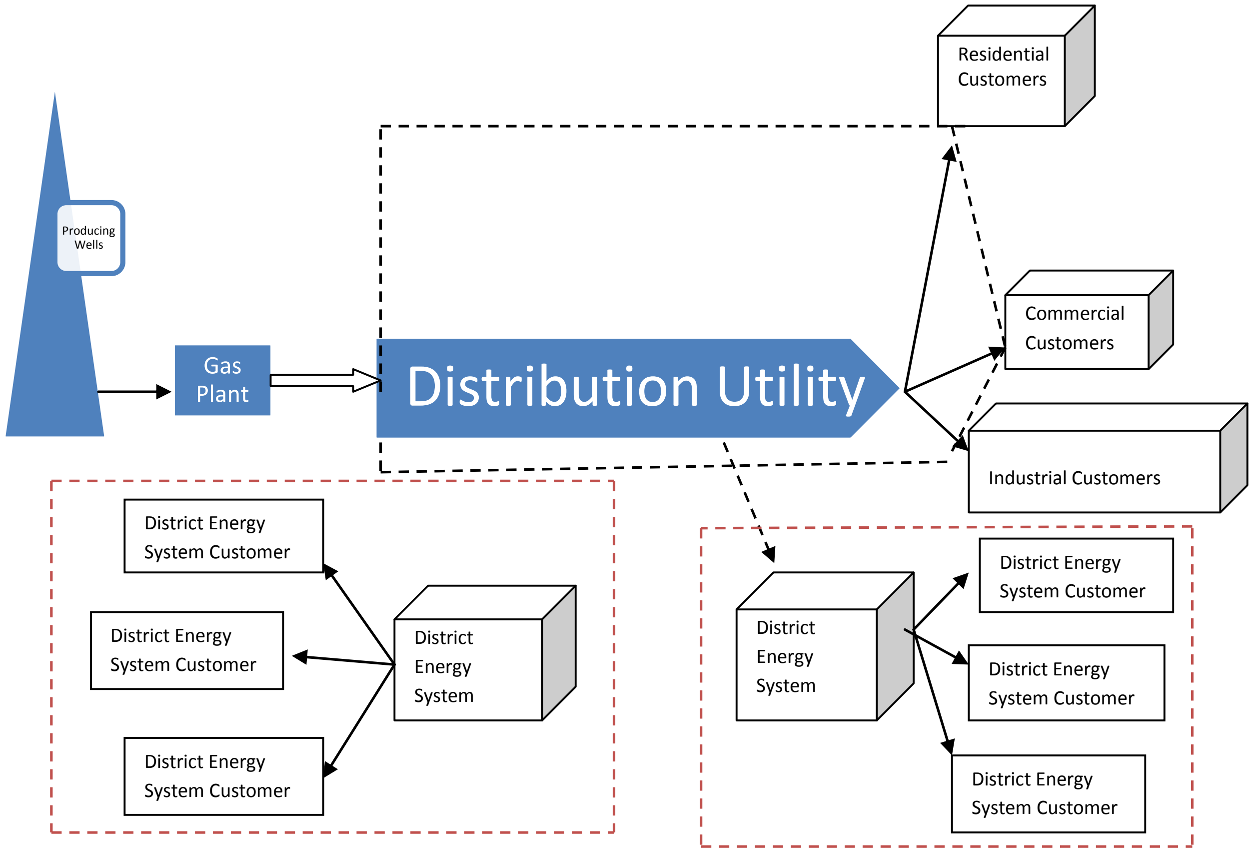
Corix agrees in principle with the need for a threshold and submits that any threshold applied must apply equally to all TES providers. (Corix Final Submission, pp. 18-19)

BCPSO and ESAC both argue for a zero threshold because those TES projects are investments in a novel line of business. (BCPSO Final Submission, p. 17; ESAC Reply Submission, p. 7)

Due to the standalone nature of each thermal district project, **the Commission agrees with BCPSO and ESAC that at this stage an appropriate CPCN threshold for TES Projects should remain at zero.**

3.5.3 Other Thermal Energy Systems

Thermal Energy Systems which have more than one customer come in a number of models and configurations. The most commonly discussed are District Energy Systems.



Introduction of District Energy Systems to the Traditional Gas Utility Model

In District Energy Systems, customers are generally served from one centralized energy source. This could consist of geothermal systems, a large gas boiler system, or other centralized sources of energy used to provide heat (and in some instances, cooling). A number of customers are attached to the central energy provision system. A traditional gas utility entering into this business may be providing natural gas to the centralized energy facilities (either as a primary energy source or as a supplementary or backup energy source). This is illustrated in the diagram above with the District Energy System connected to the distribution utility by the dashed arrow. It is also possible that the District Energy System uses no natural gas.

3.5.3.1 Key Characteristics

As Thermal Energy Systems other than Discrete Systems come in a range of configurations, their characteristics also range. The key differentiating factor is that typically, more than one customer is served.

The Panel finds that a "typical" district energy system has the following characteristics:

- Multiple customers in multiple buildings receive service through a common energy distribution system;
- The system is connected to one or more shared heat sources or central energy plants;
- There may be more than one class of customers with corresponding rates;
- There is a physically interconnected energy system, with shared or common facilities distributing thermal energy to buildings or customers within the service area; the system does not encompass equipment which is located within one building and/or site, and which is solely for the benefit of one building/customer;
- Thermal distribution piping and energy transfer stations are present;
- Thermal energy demand is uncertain because final customers, timing and building design are unknown;
- Economies of scale are present;
- The ability to increase the centralised energy supply to meet the needs of new customers exists; and
- There are multiple stakeholders, requiring multiple agreements to be negotiated, and development tends to be longer due to the greater scope and scale.

3.5.3.2 Current Status of Activities

The District Energy Systems currently regulated by the Commission are Central Heat in Vancouver, the Dockside Green Energy project in Victoria, the Neighbourhood Utility Service for UniverCity at Burnaby Mountain and the most recently approved, River District Development Project in Southeast Vancouver.

In Dockside Green, UniverCity and River District, restrictions are in place so that residents are obliged to use heat provided by the utility. In other words, in these developments customers are captive to the central heating system.

Central Heat, on the other hand, operates its steam District Energy System in the same geographic area in downtown Vancouver as BC Hydro (electricity) and FEI (natural gas). Building owners in Downtown Vancouver are not obligated to obtain space heating from Central Heat, which must compete for the business. In this system there are limited barriers to entry or exit of customers as there are other heating options available.

3.5.3.3 Key Issues

Whether Thermal Energy Services are regulated and if so, the proper form of regulation, were key issues in this Proceeding.

Where a traditional utility, with its access to a large ratepayer base, operates District Energy Systems on an integrated basis, cross-subsidization is a concern.

In the Panel's view there is a grey area as to what constitutes a Discrete Energy System as compared to a District Energy System. This, for example, could involve the service to a single strata, but with multiple customers in the strata and a need to regulate to protect customer interests.

A further issue is where ownership of the TES system is driven by financial considerations. ESAC submits:

> "one test for the Commission to apply in assessing AES projects is whether, if the project was owned by the customer, there would be any basis for regulation. In a Discrete Energy Project, with a single customer, the question of who owns the project should not determine whether regulation is required. This would be contrasted with a District Energy System, where there are multiple customers who are not owners and who must rely upon the shared use of the project and

> who are thus vulnerable to the actions of the project's owner." (ESAC Final Submission, p. 26)

Commission Determination

Need for Regulation

FEU and the Interveners concur that District Energy Systems should be regulated. ESAC submits that regulation of District Energy Systems is appropriate as they exhibit the characteristics of a "natural monopoly". In addition, as they involve multiple customers using shared or common facilities, ESAC argues that in this sense they can reasonably be regarded as providing service to "the public" and, if they otherwise meet the criteria in the definition of "public utility" in the *UCA*, they should generally be regulated. (ESAC Final Submission, p. 20; ESAC Reply Submission, p. 4)

B.C. Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA) submit that "there is no bright line between discrete and district thermal energy services. It is better to focus on the best regulatory system for the particular situation." (BCSEA Final Submission, p. 13)

The Panel finds that TES systems other than Discrete Energy Systems meet the definition of "public utility" in the *UCA*, and are regulated. However, the degree of natural monopoly characteristics and the degree of consumer protection required will affect the form of regulation.

Form of Regulation

Interveners provided a number of views on the appropriate form of regulation.

Corix submits that the form and degree of regulation should match the scope and scale of the project and the public interest in regulation to protect the customers. It notes:

> "the Commission has discretion in how it applies its regulatory mandate. In accordance with the principles established in its previous decisions and the general Canadian approach to public utility regulation, the commission should regulate only as necessary to protect the public interest – i.e. where the competitive market is failing in some respect." (Corix Final Submission, p. 1)

"Starting with a competitive market as the foundation for TES regulation has more merit than moving directly to supplant competition with a potentially unnecessary regulated approach." (Corix Final Submission, p. 17)

ESAC argues that, in the absence of competition, the only incentive for efficiency is regulation, and notes that it is very difficult to regulate efficiency. (ESAC Reply Submission, Schedule A, p. 6)

There was broad support in the Proceeding for streamlined regulation, but little clarity on what that should entail.

In keeping with the Principles and Guidelines set out in Section 2.2, the least amount of regulation to protect the ratepayer should be used. The Commission Panel has serious reservations about the applicability of the regulated cost of service model across the entire regulated TES market and reiterates the comments of the Commission in the Delta School District Decision that full cost of service regulation is the "method of last resort" (see Section 2.2 of this Report). The presence of market-based pricing or the protection of consumer interests through the execution of long term contracts may result in a better alignment and balance of risks and incentives between ratepayers and the thermal provider. Regulation by complaint may also provide the appropriate level of consumer protection.

The Commission agrees with ESAC that it is difficult to regulate efficiency, and finds that market-based pricing or long term contracts may be better at promoting efficiency, cost-reduction and enhancing performance. Regulated TES utilities are encouraged to pursue market-based pricing mechanisms to "increase efficiency, reduce costs and enhance performance" as contemplated by section 60(1)(b) of the *UCA*.

Commission Staff will be conducting consultations on a scaled regulatory framework for TES utilities, following the conclusion of this Inquiry. This process will, with further input from stakeholders, establish the form of regulation required, in accordance with the Principles and

Guidelines set out in Section 2. The framework that results from this consultation process will be brought to the Commission for approval.

Business Structure

FEU consider that the class of service model for TES captures “legitimate economies of scope” that benefit both natural gas and TES customers, and that there are a variety of sound cost-allocation methodologies that can be employed to permit the Commission to treat a thermal class of service as a self-contained unit for ratemaking purposes. (FEU Final Submission, pp. 1, 58)

As well, FEU submit that TES services are part of their energy delivery system because, in part, they almost always rely on a conventional energy source to provide backup and peak demand. (Exhibit B-17, p. 5)

Corix argues for full corporate separation of the TES and natural gas businesses with a comprehensive Code of Conduct governing inter-affiliate dealings. It argues that “FEI’s TES is a new line of business “downstream” of the FEI natural gas meter, not merely a separate class of service”. Corix submits that its proposed structure is “the most efficient and practical way to protect against the risks (to both the ratepayers and the emerging TES market itself which flow from FEI’s “strong incentive ...to take unfair advantage of its monopoly position as a natural gas distribution utility”). Corix recommends that all components of FEI’s TES business be transferred to a separate legal entity operating at arm’s length from FEI, on a fully loaded accounting basis, including accrued research and development costs. (Corix Final Submission, pp. 2, 25, 30)

Corix also submits that this structure will reduce the need for intense regulatory oversight, and the regulatory burden on all participants. Any residual costs that FEI does not include in the TES cost of service would be absorbed by the FEI TES company shareholder, not the natural gas ratepayer. (Corix Reply Submission, p. 9)

The Commission Panel agrees with Corix that TES comprise a fundamentally different line of business, occurring beyond the gas distribution meter, and cannot therefore be considered an extension of the utility distribution system.

Regarding potential cross-subsidization, FEU submit that cost allocation methodologies can be employed to address cross-subsidization concerns. The Panel observes that FEI has demonstrated the difficulty it has in tracking and documenting these costs in FEU's 2012-2012 RRA and other proceedings. The Panel finds that the presence of an approved cost-allocation methodology is not sufficient in itself to eliminate the potential for cross-subsidization, as substantial effort is required to establish appropriate accounting controls, especially when a company is undergoing a major transformation. The Panel has noted previously that separation, rather than accounting practices, minimizes the potential for abuse.

As described above, TES Projects other than Discrete Systems largely take place outside the bounds of the traditional natural gas distribution utility, and are typically a separate energy system from the regulated utility. They have different business risks and a competitive market exists for the service. **Accordingly, TES Projects that are not exempt from regulation are most appropriately undertaken through an Affiliated Regulated Business.**

GT&C12A (including its use as an economic screening tool) was made interim effective January 1, 2012 by Order G-223-11 dated December 22, 2011. **Given the Principles and Guidelines herein, it follows that no further applications should be brought forward by FEI based on GT&C12A. FEI/FAES should nonetheless review GT&C12A to determine if it can be eliminated altogether or if it requires an amendment to accommodate previously-approved TES projects.**

Any Regulated Affiliated company which intends to own and operate TES projects requires a thermal tariff. FAES should therefore bring forward a thermal tariff for Commission review and approval based on the Principles and Guidelines contained in this Report.

CPCN Thresholds

The Commission sets the CPCN threshold for TES Projects at zero as discussed in the Discrete Energy Systems section.

Cost Allocation

FEU argue that if TES is to be provided through a corporate affiliate, the best approach is to: allocate common costs to the TES affiliate using the approved formula specified in the Shared Services Agreement and to charge direct costs using the FEU's existing Transfer Pricing Policy, which contemplates fully loaded costs. Since the services are being provided to a regulated entity, and not an NRB, FEU argue that it is appropriate to modify the transfer pricing formula in this case to exclude profit, overheads and facilities fee components. (FEU Final Submission, pp. 69, 79)

BCPSO:

> "...is not satisfied that the FEU's methodology to determine the cost allocation accurately captures the incremental cost of the TES. [In BCPSO's view] [it] certainly does not capture the value of the shared services of which natural gas ratepayers are paying a larger percentage of their stand-alone costs. [BCPSO] submits that a full and transparent allocation methodology must be implemented so that natural gas ratepayers can be certain they are not cross-subsidizing the TES business." (BCPSO Final Submission, p. 11)

Corix argues FEU's current approach of allocating costs by way of timesheets "has failed to capture some of the value received by the TES business from the natural gas business." Corix details a number of areas where it believes the value received by the TES business has been under-recovered. It concludes that it is challenging for the Commission to detect cross-subsidies when they occur. "For comparison, Corix submits that in [its] case, "default" costs go to the shareholder and not a large captive customer class, greatly reducing the incentive or ability to cross-subsidize." (Corix Final Submission, pp 22-23, 25)

> "...Transfer pricing should be on a fully-loaded basis – as required by the FortisAlberta Inc. Code of Conduct...Recovering only incremental costs (as FEI proposes) would mimic the current scenario where "default costs" are borne by the natural gas business. It is patently unfair for the TES ratepayers to bear only the incremental costs that are actually recorded which then leaves the FEI

> natural gas ratepayers to bear the balance of the costs of the co-mingled FEI business platform. That cost allocation model also creates an unfair cost advantage for FEI TES projects." (Corix Final Submission, p. 2)

The Panel finds that sharing of services among affiliates should be done on the basis of the higher of market pricing or the fully allocated cost of such services in accordance with the Principles and Guidelines in this Report and an approved Code of Conduct and Transfer Pricing Policy. FEU should allocate costs accordingly.

3.6 Steps to be Followed by a Utility Endeavouring to Enter into a New Regulated Business

The Panel finds that the approach taken by FEI in entering into Biomethane Service and the Commission Decision on the Biomethane Application have a number of positive characteristics. These include:

- The Applicant coming to the Commission <u>before</u> significant funds were expended to set out:
  - (a) the proposed service offering; and
  - (b) the business model the Applicant proposed to utilize;
- Use of a pilot project to allow for testing of the proposed new service, including assessment of the reliability of biomethane supply and the sufficiency of demand for the product; and
- Providing for some growth during the pilot period but placing a limit on the cost and risk exposure faced by ratepayers and the utility by setting a cap on biomethane production.

Detailed planning of the business model and early involvement of the Commission are key elements in the efficient management of costs related to AES and other New Initiatives. Additionally, the use of a pilot program with parameters that allow for sufficient activity to test the market for a new product while providing limitations on the costs and risks represents a balanced approach to allowing new business activities to proceed. The Panel recommends that FEU or other utilities considering a new business activity take note of the example provided by the proposed introduction of Biomethane Service in any future applications.

As well, based on the content of this Report, a utility entering into a new line of regulated business should submit an application to the Commission setting out the proposed:

- Business structure;
- Form of regulation;
- Cost allocation methodology; and
- Risk allocation.

SECTION 4 SPECIFIC ISSUES REQUIRING A DECISION

4.1 Allocation of Hearing Costs

Background

Order G-118-11 (Exhibit A-5) dated July 8, 2011 set out the scope of the Inquiry and the issues to be addressed at a principles level. The allocation of the hearing costs is an issue. In the Reasons attached as Appendix A to Order G-118-11, the Commission Panel found that this Proceeding has arisen from issues raised in previous FEU proceedings and in complaints regarding FEU activities. The Panel concluded that the costs of the Inquiry should be allocated in the usual manner, i.e., as if FEU were the applicant. The Commission Panel further stated that if, at the time of final argument, FEU were of the view that this allocation of costs was not appropriate, the Commission Panel would consider arguments on how this allocation might be amended.

In their Final Submission, FEU argue that the Inquiry costs are legitimate costs of service and are recoverable from customers, and submit that the allocation of Inquiry costs as between TES and natural gas classes of service should reflect the drivers of these initiatives and where the benefits fall. (FEU Final Submission, p. 13)

FEU submit that a fair allocation of the Inquiry costs would be 75 percent to natural gas and 25 percent to TES customers. The bases of FEU's submissions are:

- Three of the four issues being considered in the Inquiry, that is, CNG/LNG Fuelling Service, Biomethane Service, and EEC, are options focussed solely on the natural gas business and provide benefits to natural gas customers;
- Past decisions relating to Biomethane, CNG/LNG Fuelling and EEC contemplated recovery of hearing costs as part of the general natural gas revenue requirement; and
- The TES offering also provides a choice to natural gas customers that want to meet their thermal energy requirements in a different manner.

BCPSO argued that while TES makes up only one of four issues considered, TES was the primary driver for the Inquiry. It suggests the cost split for the Inquiry should be 50/50 between TES and FEU's gas customers.

Commission Determination

The Commission Panel finds that while FEU's TES activities were one of the drivers for the Inquiry, considerable time and resources were focussed on other issues. The Panel accepts FEU's proposed allocation of the Inquiry hearing costs of 75 percent to natural gas and 25 percent to TES customers **and further directs that the portion allocated to TES be maintained in the current TESDA account.**

4.2 Applicability of CPCN Thresholds

FEU believe that whatever approach is ultimately applied to FEU should also apply to other public utilities. If the Commission establishes a CPCN threshold for FEU, then it should also do so for Corix and other utilities, and the same applies if no threshold is ordered. (Exhibit B-17, p. 1-2)

Corix agrees that the threshold for triggering a CPCN application should be the same for all AES service providers. The previous CPCN exemption for AES projects under $5 million was unique to FEI. Other AES service providers, like Corix, must apply for a CPCN when the proposed service brings the service provider within the definition of "public utility" under the *Utilities Commission Act*. Corix argues that the presence of a different threshold for FEI versus other parties would serve to significantly reduce FEI's regulatory burden relative to its competitors which is unfair and not in the public interest. Corix submits all AES service providers should be treated equally. (Exhibit C12-11, p. 1)

Commission Determination

The Panel agrees with FEU and Corix, and finds that where a CPCN threshold is found to be appropriate, it will apply equally to all parties.

4.3 Administration of Demand Side Management and Other Incentive Funding

4.3.1 Current Status of Activities

FEU design and administer Demand Side Management (DSM) programs (referred to by FEU as Energy Efficiency and Conservation or EEC Programs) in accordance with the requirements of the *Utilities Commission Act* and the *Clean Energy Act,* including applicable regulations.

Utilities propose DSM expenditure schedules which the Commission reviews and accepts or rejects on a regular basis. These expenditure schedules typically set out: (a) who is eligible; (b) the level of the incentive to be provided; and (c) the activities that must be undertaken to receive the incentive, for each DSM program. DSM is funded by the traditional utility ratepayers.

The FEU have DSM programs that provide incentives for TES projects. Corix and ESAC have raised concerns about the way DSM funds are currently administered by the FEU. In particular they argue: i) provision of DSM funds creates a risk of cross-subsidization from the traditional natural gas ratepayer to the TES customer; and ii) there is a risk that if the FEU have preferential access to DSM incentives for their own projects, they will have a competitive advantage in the TES market. (Corix Final Submission, pp. 27-30) ESAC refers to "an inherent conflict of interest in allowing a regulated utility to collect [DSM] funds and then, while acting effectively as a trustee of those funds, to ensure the funds are properly allocated when the utility or its affiliate is in a position to benefit from allocation decisions." (ESAC Final Submission, para. 12)

Corix recommends that third-party administration of FEU DSM funds should be required while ESAC recommends that the management of EEC funds for projects in which the FEU is involved should be made subject to a Code of Conduct. (Corix Final Submission, pp. 27-30; ESAC Final Submission, paras. 132, 136)

BCPSO agrees that a Code of Conduct could work but strongly objects to outsourcing EEC management because it poses administrative and regulatory "pitfalls." (BCSPO Final Submission, p. 23 and Reply Submission, p. 2)

CEC submits that in its view, there is no issue with EEC funding and thus third party assessment is unnecessary. (CEC Final Submission, p. 29)

BCSEA agrees that the administration of EEC funds should be transparent but submits that most of the FEU's DSM funding is not for TES and it is not desirable to disrupt that funding. (BCSEA Final Submission, p. 11 and Reply Submission, pp. 2-3)

The FEU propose that EEC funding decisions remain with them because their existing mechanisms ensure funds are made available in an impartial manner. They propose specific guidelines for the administration of the funding, including:

> "(a) The FEU establish EEC programs and determines (sic) incentive criteria, set in terms and conditions;
>
> (b) The FEU inform customers about the EEC programs through different communication channels;
>
> (c) Customer identifies its EEC needs to the FEU;
>
> (d) Customer completes its EEC improvements/investments;
>
> (e) Customer applies to the FEU for EEC incentives;
>
> (f) Applications are reviewed by the FEU to ensure that the program criteria outlined in the terms and conditions of the EEC program are met;
>
> (g) Incentives are distributed to customers, and not to the third party project partner (whether that is Corix, ESAC member, or the FEU); and
>
> (h) Customer selects the TES project partner that it sees fit, applying its incentive dollars towards the project cost, if they so choose to use the incentive to reduce their rate for the TES project.
>
> ... Third parties interested in partnering with customers are responsible for finding out what EEC is offered and can encourage their customer-partners to apply to the FEU forincentives." (Exhibit B-2, p. 155)

The FEU submit that their current mechanisms and Commission oversight are adequate to ensure the fair administration of EEC funds. The FEU propose that as an additional low cost measure, they could report on any incentive granted to TES projects in their EEC annual reports. Alternatively, the FEU are amenable to contract with a third party engineering firm to assess EEC incentives for all TES projects, regardless of ownership or the proponent. (FEU Final Submission, para. 271)

4.3.2 Key Issues

In respect of DSM funding, the key issue before the AES Inquiry Panel relates to those cases where FEU are the direct or indirect beneficiary of the funds that they are awarding. As participants in the AES market (building and/or operating AES projects) and as distributors of DSM funds, two concerns arise for the Commission:

- Where FEU are the direct or indirect beneficiary of funds being awarded by themselves, there is a conflict of interest with the potential for preferential treatment; and
- The potential exists for DSM funds to be used to partially pay for a utility asset included in a project where the utility is already earning a full return on that asset. When this occurs, the utility earns a full return on the asset plus a further return on the DSM funds used to finance the asset. This can occur where there is a lack of definition as to where incentive funds are to be expended.

Commission Determination

The Commission Panel finds that where there is a potential conflict of interest because the FEU may be providing capital or services to a project receiving the DSM or other incentive funds, there should be a neutral third party involved in the decision making process to award such funds. FEU's proposed guidelines do not sufficiently protect against this potential conflict of interest. Accordingly, the FEU are directed to bring forward a proposal for mechanisms for approval and administration of funds by a neutral third party where the FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that funding.

To prevent the possibility of the utility potentially earning a double return, the Commission Panel is of the view that the presumption should be that incentive funds are being used to reduce the capital cost of the FEU assets, in those instances where the Company is providing capital equipment to a project that is receiving DSM or other incentive funds. In practice, this will require FEU to rebut this presumption. Where this is not done, the Panel recommends that the cost of these capital assets be reduced by the amount of the incentive funds prior to the assets being added to rate base.

4.4 Treatment of the Thermal Energy Services Deferral Account

Background

Commission Order G-141-09 approved the TESDA (then the New Energy Solutions Deferral Account) as part of the 2010-2011 Revenue Requirement Negotiated Settlement. The TESDA was agreed to be an appropriate mechanism to address allocation issues between FEI's traditional natural gas distribution customers and FEI's AES customers for costs incurred by FEI to provide Alternative Energy Services.

The following costs are currently allocated to the TESDA:

- Overhead - using an annual allocation to represent the administrative costs of supporting TES services;
- Sales and marketing - based on the 12 employees in the TES Group as well as any direct time from other employees in other areas of the Companies and certain contributions to industry associations; and
- Direct costs - which relate to a particular project or projects and may be capitalized as part of project costs, such as feasibility studies, design and construction of various actual thermal energy projects.

The balance in the TESDA as of May 31, 2012 was $7.5 million, including amounts allocated for both discrete energy systems and district energy systems pursued by FEI.

This balance has accrued from a number of FEI AES projects that have been reviewed by the Commission. In its decisions, the Commission has made a number of determinations that have implications on the treatment of TESDA, including:

Delta School District Decision

- A subset deferral account of the TESDA was created and will be separately tracked from other AES projects in the future. In other words, the School District is fully responsible for its proportional share of the TESDA balance;
- The entire TESDA is to be maintained within FEI until such time as the Panel in the AES Inquiry directs otherwise. (Delta School District Decision, pp. 96, 100)

Tsawwassen Springs Decision

- FEI's proposal for the Tsawwassen Springs Project, i.e. that any variances between forecast project costs and revenues would accrue in the TESDA, to be recovered from all TES customers (except the Tsawwassen Springs customer), before the shareholder would be at risk was found to be an inappropriate use of the TESDA.
- The TESDA should include only general costs that apply to all thermal projects and cannot easily be directly allocated to a particular project, and balances in the TESDA should be recovered in a fair and timely manner from all thermal customers to prevent cross-subsidization of some TES customers and not others. (Tsawwassen Springs Decision, pp. 20, 35-36, 40-42)

PCI Marine Gateway Decision

- Concern was raised over the current use of the TESDA to mitigate the business risk of the shareholder, by making TESDA primarily responsible for any residual stranded costs in the event that all Marine-Gateway customers leave the system. Only in the event that there are no thermal customers sharing in the TESDA would the ultimate risk fall to Fortis shareholders.

Commission Determination

The Panel concludes that the current TESDA, now maintained within FEI, should be reviewed and a methodology developed for its allocation and recovery. FEI is directed to file an application that sets out:

(a) the circumstances where a deferral account would be established for a specific Thermal Energy Services project;

(b) a methodology that defines costs that are allocated to the general TESDA and costs that may be allocated to a project-specific deferral account;

(c) the types of costs that would be allocated to the TESDA or to a deferral account related to a specific Thermal Energy Services project;

(d) a methodology for the recovery of the current TESDA, including setting out a timeline for the recovery of the current balance;

(e) a methodology for the allocation and recovery of future additions to the TESDA including a timeline for the recovery of balances; and

(f) a methodology that will allow any allocation of balances in the TESDA to be assigned to specific TES customers or to the utility shareholder in a manner that is fair and reasonable.

DATED at the City of Vancouver, in the Province of British Columbia, this 27th day of December 2012.

Original signed by:

N.E. MACMURCHY
PANEL CHAIR AND COMMISSIONER

Original signed by:

D.A. COTE
COMMISSIONER

Original signed by:

L.A. O'HARA
COMMISSIONER

Original signed by:

A.A. RHODES
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-201-12

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

and

An Inquiry into FortisBC Energy Inc.'s
Offering of Products and Services in
Alternative Energy Solutions and Other New Initiatives

BEFORE: N.E. MacMurchy, Panel Chair
D.A. Cote, Commissioner
L.A. O'Hara, Commissioner
A.A. Rhodes, Commissioner

December 27, 2012

O R D E R

WHEREAS:

A. On May 24, 2011, the British Columbia Utilities Commission (Commission) issued Order G-95-11 establishing an Inquiry into FortisBC Energy Inc.'s (FEI) transformation into an integrated energy service provider. A Commission staff working paper on scoping of issues was attached as Appendix B to Order G-95-11 to facilitate discussions at the First Procedural Conference scheduled on June 15, 2011;

B. At the First Procedural Conference the Commission Panel heard submissions from all Parties on the issues and scope contained in the staff working paper, and on alternative regulatory processes and timelines. On July 8, 2011, the Commission issued Order G-118-11 setting out the scope of the proceeding along with a Regulatory Timetable set out as Appendix C to that Order;

C. The Inquiry into Alternative Energy Services and New Initiatives (AES Inquiry) was established to evaluate three major issues:

   i. What principles or guidelines should be followed by the Commission to protect the public interest, what process should the Commission use before it allows the utility to undertake AES and New Initiatives, and how should Energy Efficiency and Conservation (EEC) funds or other incentive funds being made available to support AES and New Initiatives be administered to ensure fair, effective and non-discriminatory treatment;

   ii. What are the principles that should be applied to determine whether an AES or other New Initiatives project can or should be pursued as a Regulated Business;

iii. What standards should the Commission apply to determine whether the activity being carried out by the utility is done in the most cost-effective manner and what principles or guidelines should be applied to ensure that, where feasible, competitive forces can be utilized.

D. The AES Inquiry was set to address the issues at a principles level and not as a means to re-open past decisions of the Commission or to impinge on any regulatory processes that are underway before the Commission. The Inquiry would focus on the activities of FEI but the Commission expects that principles established in the Inquiry would be of wider application beyond FEI to other utilities in future proceedings;

E. By Order G-164-11 issued on September 23, 2011, the Commission amended the regulatory timetable and ordered a Second Procedural Conference for January 25, 2012;

F. Registered Interveners who filed evidence in this Inquiry included the Energy Services Association of Canada, Ferus Inc., Corix Utilities Inc. (Corix), Clean Energy Fuels, and the Coalition for Renewable Natural Gas;

G. On December 22, 2011, the Commission issued Order G-223-11 and determined General Terms and Conditions (GT&C) 12A for AES projects as interim, effective January 1, 2012. On January 4, 2012, the Commission issued Order G-4-12 and established a zero dollar threshold for a Certificate of Public Convenience and Necessity (CPCN) application effective the date of the order and invited submissions from all Parties on the appropriate CPCN threshold(s) for AES and other New Initiatives;

H. By Order G-9-12 issued on January 31, 2012 after the Second Procedural Conference, the Commission ordered a zero dollar CPCN threshold on an interim basis for AES projects and New Initiatives other than Biomethane projects, with a final CPCN threshold to be determined at the completion of the Inquiry;

I. Order G-9-12 also determined that the review of the Inquiry would proceed by way of a Written Hearing Process with Submissions and Reply Submissions to take place between March 15, 2012 and April 24, 2012;

J. On February 7, 2012, the Commission issued Order G-14-12 which accepted for filing the GT&C 12B relating to tariffs for vehicle fuelling stations;

K. On May 14, 2012 the Lieutenant Governor in Council approved and ordered the Greenhouse Gas Reduction (Clean Energy) Regulation (Section 18 Regulation). By letter dated May 17, 2012, the Commission established a timetable to allow Parties to make submissions that would form part of the record in the AES Inquiry related to the significance of the Section 18 Regulation. The last date of the argument phase was June 8, 2012;

L. The Commission Panel has considered the evidence and submissions filed by all Parties.

.../3

NOW THEREFORE pursuant to sections 23, 72, 82 and 83 of the Act, the Commission orders that:

1. The principles and guidelines set forth in the attached Inquiry Report shall apply to regulated public utilities who provide products and services outside traditional utility activities.

2. The CPCN thresholds, as applicable and as determined and set forth in the Inquiry Report, apply to all regulated public utilities.

3. FEI is directed to file an application to address the allocation and recovery of the TESDA account as set forth in the attached Inquiry Report.

4. The costs of this Inquiry are to be allocated 75 percent to FEU's natural gas customers and 25 percent to FEU's Thermal Energy customers.

DATED at the City of Vancouver, in the Province of British Columbia, this 27th day of December 2012.

BY ORDER

Original signed by:

N.E. MacMurchy
Panel Chair

GLOSSARY

Alternative Energy Services and New Initiatives	Offerings of products and services that are alternative to those offered by the traditional gas distribution utility. Denotes both current and future energy services. Since 2009, the Alternative Energy Services and New Initiatives project filed by FEI for regulation are in the areas of thermal energy services, natural gas for transportation, and biomethane. See also *Alternative Energy Services* and *Thermal Energy Services.*
Alternative Energy Services	As specified in FEI's tariff General Terms and Conditions (GT&C) 12A and FEI's 2010/2011 Revenue Requirement Negotiated Settlement Agreement, AES include geo-exchange, solar-thermal and district energy systems. *See also Thermal Energy Services.*
Affiliate	For the purpose of this Decision, an affiliate of a regulated utility is another entity directly or indirectly owned or controlled by the same shareholders of the utility, and the affiliated business may also be regulated by the Commission or may operate as a non-regulated business. This Decision does not address how an "affiliate" should be further defined for other purposes, for example, in a Code of Conduct context.
Biomethane Service	The distribution of biomethane to customers.
Class of Service	Section 60 (1)(c) of the *Utilities Commission Act* contemplates a public utility offering more than one class of service. Multiple classes of service separate or compartmentalize operations within a utility.
CNG Service	The compression and subsequent dispensing of compressed natural gas.
Code of Conduct	An established standard with conditions for interaction between a utility and its affiliates (utility and/or non-utility).
Cost of Service Regulation	A methodology where the total forecast costs to be incurred will be recovered from the customers of the utility. Total costs include depreciation, all related accounting costs, applicable property and income taxes, as well as the appropriate return on rate base as approved by the Commission for the utility.

Discrete Energy Systems	A Discrete Energy System is typically limited to a single site or customer.
District Energy Systems	District Energy Systems involve the provision of central heating and sometimes cooling services. District energy systems typically consist of one or more central energy plants connected to buildings via a network of pipes.
BC's Energy Objectives	In 2007, the provincial government of BC released its Energy Plan, which was followed by the passage of the *Clean Energy Act* (June 2010). The *CEA* sets out BC's energy objectives including: ...(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... (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; (l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;...
Greenhouse Gas Reduction (Clean Energy) Regulation	The regulation is made pursuant to section 18 of the *CEA.* The regulation supports traditional ratepayers providing limited incentives and other funding for certain CNG and LNG activities in certain circumstances and for a limited time period. See also *Prescribed Undertaking* and *Section 18 Regulation*.

Levelized Rate	Levelizing is a method of converting a non-uniform stream of future costs into a present value equivalent uniform stream of costs.
LNG Service	The onsite storage and dispensing of LNG through specialized fuelling stations
New Business Activities	A synonym to *Alternative Energy Services and New Initiatives*.
Prescribed Undertaking	A Prescribed Undertaking is an activity prescribed by Section 18 of the *CEA*. A Prescribed Undertaking is defined as "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia". The *Greenhouse Gas Reduction (Clean Energy) Regulation* identifies certain activities of public utilities which support the use of CNG and LNG for transportation as Prescribed Undertakings.
Section 18 Regulation	The provincial government passed the Greenhouse Gas Reduction (Clean Energy) Regulation under Section 18 of the *CEA.* The regulation permits a public utility, as a Prescribed Undertaking, to expend a total of $104.5 million in direct incentives and other expenditures related to the purchase of "eligible vehicles" and the purchase or construction and operation of CNG or LNG facilities. See also *Prescribed Undertaking*.
Thermal Energy Services	FEU use TES to describe activities formerly known as Alternative Energy Services in the Inquiry. The TES projects filed by FEI with the Commission cover a broader range of technologies than was considered in its tariff GT&C 12A. In this Decision, TES is used interchangeably with AES.
Transfer Pricing Policy	A policy document which addresses the pricing of resources and services provided by the regulated utility to: (i) an NRB; (ii) a division of the utility providing unregulated products or services, and/or; (iii) a regulated affiliated utility. The aim is to protect the core ratepayers from subsidizing unregulated activities or new regulated activities.
Biomethane Upgrader	Equipment used to upgrade raw biogas to pipeline quality biomethane. Upgrading facilities are not an extension of the gas distribution system.

LIST OF ACRONYMS

AES	Alternative Energy Services or Alternative Energy Solutions
BCPSO	British Columbia Pensioners' and Seniors' Organization, *et al*.
BCSEA	B.C. Sustainable Energy Association and the Sierra Club of British Columbia
Commission	British Columbia Utilities Commission
CEA	Clean Energy Act
CEC	Commercial Energy Consumers of B.C.
Clean Energy	Clean Energy Fuels
CNG	Compressed Natural Gas
Corix	Corix Utilities Inc.
CPCN	Certificate of Public Convenience and Necessity
CRNG	Coalition for Renewable Natural Gas
DSM	Demand Side Management
DES	District Energy Systems
EEC	Energy Efficiency and Conservation
ESAC	Energy Services Association of Canada
FEI	FortisBC Energy Inc.
Ferus LNG	Ferus Inc. LNG Division
FEU	FortisBC Energy Utilities
GT&C	General Terms and Conditions
LTRP	Long Term Resource Plan
LNG	Liquefied Natural Gas
MEM	Ministry of Energy and Mines
NGV	Natural Gas Vehicle
NRB	Non-Regulated Business
O&M	Operating and Maintenance

CRNG	Coalition for Renewable Natural Gas
RMDM	Retail Market Downstream of the Meter
TES	Thermal Energy Services
TESDA	Thermal Energy Services Deferral Account
TGI	Terasen Gas Inc.
UCA	*Utilities Commission Act*

SUMMARY OF PROCESS

By Order G-95-11 issued on May 24, 2011, the Commission determined that an inquiry into FEI's transformation from a traditional gas distribution utility into an integrated energy provider (Inquiry) was warranted.

FortisBC filed a number of applications to the British Columbia Utilities Commission (the Commission) for approval to provide products and services in alternative energy services and other new initiatives. These applications led to a series of *ad hoc* Commission Decisions and Orders. In each of these proceedings, as cited in the recitals to Order G-95-11, registered Interveners raised issues with respect to the scope of regulation as it relates to these new initiatives.

In their most recent Long Term Resource Plan (2010 LTRP), Terasen Utilities [as the FortisBC Energy Utilities (FEU) were formerly known], stated that "going forward, the utilities will seek approval of an overall business and regulatory model and seek CPCN approval of specific projects." The Commission Panel in that proceeding commented that this statement raised the issue of the need to better understand the utilities' view of the line separating regulated and non-regulated activities, as the companies pursue what some might define as potentially competitive enterprises, as opposed to more traditional activities.

The regulatory questions that arose in the 2010 LTRP proceeding resulted in the following findings, among others[1]:

- Each 'unique situation' as FEU describe their new initiatives, needs to be tailored within a regulatory policy framework to be determined after a more holistic review;
- The changes being contemplated by FEU and the issues arising from them are significant enough to warrant a formal process to address them at a future date.

On April 27, 2011, the Energy Services Association of Canada (ESAC), an industry association of member energy service companies, applied to the Commission requesting that the Commission exercise its general supervisory powers under section 23 (1) of the *Utilities Commission Act* (the *UCA*) to inquire into the practices and conduct of FEI in the Alternative Energy Services (AES) business and to make such orders as it considers appropriate to protect the public interest. (Exhibit A2-1,)

[1] *In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. 2010 Long Term Resource* Plan; Decision and Order G-14-11, February 1, 2011 (2010 LTRP Decision).

On May 6, 2011, Corix Utilities (Corix) filed a letter in support of ESAC's application, citing that Corix has similar concerns about FortisBC's AES activities, albeit from a different market perspective. (Exhibit A2-2)

The Complaint Letter from ESAC

The Complaint Letter lists four specific concerns ESAC has with FEI:

1. A lack of adequate public consultation by FEI;
2. The use and distribution of Energy Efficiency and Conservation (EEC) Funds by FEI;
3. The role of a "regulated utility" (FEI) in the delivery of Alternative Energy Services (AES) and the potential cross-subsidization of AES activities by natural gas rate payers;
4. The inappropriate use of sensitive market information within FEU.

ESAC asked the Commission to undertake the following actions:

1. Create an unbiased entity or group to oversee the distribution of all EEC funds that are obtained from FEI's natural gas rate payers and to ensure that all industry participants have equal access to receive these funds for worthwhile projects;
2. Ensure the natural gas rate payers of FEU are not supporting the AES endeavours of FEI or its affiliates. This should require that the AES activities should not be undertaken within the natural gas utility or by a subsidiary thereof;
3. Ensure that the market information that resides within the natural gas utility is not shared with the AES business so as to create a competitive advantage not enjoyed by other industry participants. This should require that people, offices, and resources are not shared between the natural gas utility and the AES business unit(s) within FEI.

Corix Utilities' Letter in Support of ESAC's Letter

Corix alleged that the market for alternative energy services and systems, both small regulated utility operations and non-regulated energy services, is a competitive market that is currently well served by companies such as Corix and others. It submits that FEI's participation in this market through its AES business is open to abuse of its market power which would frustrate the development of this important market and harm the public interest.

In its letter, Corix described FortisBC as building a new energy service utility within the existing gas utility structure.

Order G-95-11 and G-118-11

Order G-95-11 established the Inquiry into FEI offering Products and Services in Alternative Energy Solutions and New Initiatives. Comments were also sought from the parties on the scope of issues for the Inquiry.

FEU defined AES as only related to geoexchange systems, solar thermal and district energy systems.2 The description of AES can be found in the General Terms and Conditions 12A (GT&C 12A) in the FEI tariff. The Commission Panel, however, did not see merit in narrowly defining the term AES or new and innovative energy technologies for the purpose of the Inquiry.

After the First Procedural Conference, the Commission issued Order G-118-11 (Exhibit A-5). The Order provided that this Inquiry will address issues at a principles level, and consider all types of AES and new initiative activities, including the application of EEC or other funding.

In the Evidence of FEU, the Companies summed up "AES and other New Initiatives" as related to:

- The FEU's ownership of facilities that upgrade raw biogas into biomethane for the sale to the FEU customers under the Biomethane Service;
- Natural gas vehicle (NGV) fuelling service, which involves the provision of Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) to customers under service agreements; Thermal Energy systems or Thermal Energy Services (TES)[3] or projects offered under the FEI GT&C 12A: Alternative Energy Extensions; and
- Their EEC program. (Exhibit B-2, p. 1)

As the Inquiry was triggered in part by the Complaint Letter and the identification of issues raised in past FEI proceedings, the focus of this Inquiry was determined to be on FEI. The Commission Panel also acknowledged that the outcome of the Inquiry could have application beyond FEI to other utilities engaged, or who become engaged, in similar activities or programs.

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[2] The definition can be found in Section 13 of the Negotiated Settlement Agreement of FEI (formerly TGI) 2010 and 2011 revenue requirements application which was approved by Order G-141-09.
[3] The reference to TES first appeared in the Evidence filed by FEU in the Inquiry proceeding. FEU consider that TES describes what was formerly known as AES as TES is more descriptive. In the Delta School District Decision the Commission found that the original AES concept contemplates providing access to alternative energy sources and solutions in conjunction with the gas system rather than just the provision of thermal energy.

The Commission Panel also established, in the Inquiry's Terms of Reference (Appendix B to Order G-118-11), that this Inquiry is not a vehicle to re-open past decisions.

Interveners, Key Stakeholders and the Regulatory Process

Interveners and Key Stakeholders

The stakeholders in this Inquiry are FEI, its shareholders and ratepayers, ESAC, Corix and other Registered Interveners who may be affected by the way FEI does business in AES and New Initiatives. The key stakeholders who registered as Interveners were:

- ratepayer groups – Commercial Energy Consumers Association of BC (CEC), British Columbia Seniors' and Pensioners' Organization (BCPSO);
- environmental group – BC Sustainable Energy Association and Sierra Club of British Columbia (BCSEA et al.);
- other public utilities – Pacific Northern Gas (PNG), British Columbia Hydro and Power Authority (BC Hydro);
- Potential competitors to FEU in AES and New Initiatives – Clean Energy Fuels (CEF), Coalition for Renewable Natural Gas (CRNG), Ferus Inc. (Ferus); Business and industry groups – Greater Vancouver Home Builders' Association (GVHBA), PCI Developments (PCI), Urban Development Institute (UDI) Coalition;
- Others – Ministry of Energy and Mines (MEM), Canadian Office and Professional employees' Union, Local 378 (COPE 378), Thermal Environmental Comfort Association (TECA), Artex Barn Solutions (ABS).

Ten parties also registered as Interested Parties to the Inquiry proceeding.

The regulatory process included one round of Information Requests (IRs) on FEU's Evidence. The following Registered Interveners also filed Evidence and all parties were provided with the opportunity to ask one round of IRs. Evidence was put forward by the following parties:

- Energy Services Association of Canada;
- Ferus Inc.;
- Corix Utilities;
- Clean Energy Fuels;
- Coalition for Renewable Natural Gas.

On January 4, 2012, the Commission issued Order G-1-12 which set the threshold for Certificate of Public Convenience and Necessity (CPCN) at zero dollars for AES and other New Initiatives projects on an interim basis (Exhibit A-17). Prior to this Order, the CPCN threshold was $5 million for AES projects under GT&C 12A. All parties were provided with the opportunity to file written submissions on the appropriate CPCN thresholds.

On January 31, 2012, following the Second Procedural Conference, the Commission issued Order G-9-12. The Commission ordered, among other things, that: (i) a zero dollar CPCN threshold be established on an interim basis for AES projects and New Initiatives other than Biomethane projects, with a final CPCN threshold to be determined at the completion of the Inquiry; (ii) a $5 million CPCN threshold be set for Biomethane activities, with a final CPCN threshold to be determined at the completion of the Inquiry (Exhibit A-20).

Order G-9-12 also established a written hearing format with the last day of Reply arguments being April 24, 2012.

On May 14, 2012, the Lieutenant Governor in Council approved and ordered the Greenhouse Gas Reduction (Clean Energy) Regulation under section 18 of the *Clean Energy Act* (*CEA*). (Section 18 Regulation) As a result of the promulgation of the section 18 Regulation, the Commission sought submissions to address matters arising from section 18.

The last date of the Inquiry Proceeding was June 8, 2012.

Requests from Participants and Orders Sought

The Inquiry is a Commission initiative the purpose of which is to address issues raised in the Complaint Letter as well as issues raised by key stakeholders within the scope as established in Order G-95-11. In the absence of an applicant seeking approvals or requesting acceptance, the following are brief summaries of requests made by three key parties: FEI, ESAC and Corix:

FEU

- The overarching objective is to restore a measure of certainty. The Commission should give weight to the merits of maintaining regulated options for customers within a regulatory framework that permits customers to retain the benefits of legitimate economies of scope.
- The Inquiry and resulting Guidelines should be focused on the four New Initiatives and not seek to anticipate other future offerings.
- The Inquiry and the resulting Guidelines should address how, not if, the FEU provide the New Initiatives.

- The allocation of Inquiry costs as between TES and natural gas classes of service should reflect the drivers of these initiatives and where the benefits fall. FEU submit that an allocation of the Inquiry costs of 75 percent to natural gas ratepayers and 25 percent to TES ratepayers would be fair to customers. (FEU Final Submission, pp. 3-13)
- The Commission should implement TES Guidelines that contemplate:
    - A CPCN threshold for TES of $5 million;
    - Differing content requirements for TES project-related applications depending on a project's particular size and complexity; and
    - Streamlined rate regulation once the initial approvals are in place. (FEU Final Submission, p. 55).
- The use of the FortisBC name to market TES is appropriate.
- Debt financing for stand-alone the TES project should reflect an allocated amount at FEI's embedded cost of debt. (FEU Final Submission, p. 62, para. 142)
- Whatever the outcome of this Inquiry, the FEU must be provided with a mechanism by which to recover prudently incurred costs in the Thermal Energy Services Deferral Account (TESDA).

<u>ESAC</u>

- It is crucial that the Commission not authorize the FEU to engage in business practices in the AES market free from the constraints of the *Competition Act* unless the Commission is also prepared to diligently oversee those activities to ensure that there is no abuse of market dominance. (ESAC Submission, p. 16)
- District Energy Systems, serve "the public" and a cost of service model is likely to be the most appropriate. (ESAC Submission, p. 20)
- For Discrete Energy Systems, the principles underlying the RMDM Guidelines continue to be relevant to guide the Commission in its oversight of the utility. (ESAC Submission, pp. 21, 26)
- For business enterprises that are not otherwise "public utilities" (such as NRBs) whose activities might fall within the definition of a "public utility", the Commission should forbear from regulation where that activity is conducted in an open and competitive market. (ESAC Submission, p. 21)
- The Commission should seek to find legal and practical boundaries to the scope of its jurisdiction to achieve a realistic and manageable result consistent with the objective of the legislation. The Commission should not allow itself or the UCA to be used as an instrument by which the FEU can stifle competition and effectively expand their monopoly and market dominance. (ESAC Submission, p. 23)

- Ratepayers are entitled to expect a full return on their investment in surplus capacity including full compensation for any and all risk associated with the use of that capacity in support of any other business. (ESAC Submission, p. 30)
- Information should be treated the same as a transfer from the established utility to any unrelated party. The regulated utility should charge a market price for that information and should make the information freely available to all parties willing to pay. (ESAC p. 32).
- The management of EEC Funds should be made the subject of a code of conduct. (ESAC Submission, p. 33)

<u>Corix</u>

- FEI should be directed to transfer its TES business to a separate legal entity that operates at arm's length from FEI.
- The transfer should include all components of the TES business on a fully loaded accounting basis, including accrued research and development costs.
- The Commission should establish guidelines similar to RMDM, a Transfer Pricing Policy and a Code of Conduct to govern interactions between affiliated public utilities.
- The Commission should adopt light-handed (complaint-based) regulation for TES projects below a $5 million threshold.
- Any exemptions for TES projects should apply equally to all TES service providers.
- FEI should transfer the administration of the EEC program to a third party who would ensure the funds are available equally to all TES providers. (Corix Submission, pp. 2, 3)

<u>A2 Exhibits</u>

Counsel for FEU expressed a concern as to the large number of A2 (or Commission staff) exhibits on the record and how they might be handled. The Panel Chair advised that A2 exhibits did not represent any particular position, but were placed on the record for the use of all parties, and saved having them be introduced into the evidentiary record as IR responses. (T2: 149-151)

RETAIL MARKETS DOWNSTREAM OF THE METER GUIDELINES

5 0 COMMISSION GUIDELINES WITH RESPECT TO UTILITY OR NRB PARTICIPATION IN DOWNSTREAM RETAIL MARKETS

5.1 Use of Utility Assets and Services in the Downstream Retail Market

5.1.1 Jurisdiction

Based on the submissions received as well as the legal opinion sought by staff, the Commission understands its jurisdiction with respect to the use of utility assets and services to provide unregulated goods and services to be as follows.

The Commission does not have the power to control the activities or to determine what services an NRB will provide if the NRB is a self-financing, stand-alone, arm's length affiliate using no resources of the utility.

The Commission has the jurisdiction to regulate the relationship between a public utility and an affiliated NRB to the extent that the relationship affects ratepayers. The Commission may implement a transfer pricing policy to regulate the interface between the utility and the NRB or may prohibit a utility from providing an NRB with any utility assets and services if, in the Commission's judgment, this is required to protect ratepayers.

The Commission has the jurisdiction to prohibit a public utility from participating in retail markets downstream of the meter if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers. In this case, the parent corporation of the utility may still decide to create a subsidiary NRB to participate in the retail market downstream of the meter. Alternatively, the Commission may implement a transfer pricing policy to regulate the interface between the regulated and unregulated activities of the utility if in the Commission's opinion this provides ratepayers with sufficient protection.

The Commission supports the general position of staff that determinations regarding the extent and manner in which utility assets and services may be used to provide goods and services to the downstream retail market should be made on a basis which takes into account individual circumstances. However, it is clear from the submissions received and the legal opinion that certain changes to the specific objectives, criteria and principles initially proposed by staff are needed. The objectives, criteria and principles which the Commission intends to use to guide its determinations regarding the extent to which utility assets and services may be used to provide goods and services to the downstream retail market are outlined below.

5.1.2 Objectives

Based on the information received, it is clear that the Commission has jurisdiction to consider the first two objectives given in the staff position paper when considering the extent to which utility assets and services may be used to provide goods and services to the downstream retail market. Conversely, the Commission finds that it has no jurisdiction to consider the impacts of the use of utility assets and services, either directly or through NRBs, on the retail market downstream of the meter. Accordingly, the fourth staff objective, that customer choice should be maximized, and the additional objective proposed by Enron, that robust competition in downstream markets should be preserved and enhanced, are beyond the responsibilities of the Commission in making its determinations.

With respect to the third objective identified by staff, that the most efficient allocation of goods and resources should be sought, the Commission believes that this forms a proper part of its consideration, but only to the extent that ratepayers are affected. Accordingly, the Commission believes that it may consider whether a proposal would enhance or reduce the possibility of stranded utility assets, or otherwise increase the economic efficiency with which utility assets are used for the benefit of ratepayers, but may not consider the implications for economic efficiency with respect to the larger market. The Commission accepts the concern voiced by some parties that a precise measurement of economic efficiency is not possible, particularly when considered from a societal perspective, but expects that it is possible to determine directionally whether a particular proposal enhances or reduces the likelihood of stranded costs or otherwise provides benefits to ratepayers.

Accordingly, the objectives which will guide the Commission's determinations with respect to utility and NRB participation in the retail market downstream of the meter are as follows.

Figure 6: Commission Objectives

There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers.
The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity, that is the risks must have no impact on utility ratepayers.
The most economically efficient allocation of goods and resources for ratepayers should be sought.

In addition, the Commission agrees with staff that greater achievement of one objective may require a lesser achievement of another objective so that trade-offs may be required. The Commission will be the sole arbiter of how the trade-off between objectives should be made in determining the extent and manner in which utility services and assets may be used to participate in the retail market downstream of the utility meter.

5.1.3 Criteria

With regard to the six criteria proposed by staff, the Commission has concluded that they should be revised as follows:

i) Does a natural monopoly currently exist for the good or service?

ii) If the good or service is not a natural monopoly, can the utility ratepayer be sufficiently protected through a transfer pricing policy mechanism if either a division of the utility or a related-NRB offers the good or service?

iii) Will the use of utility assets or services in the provision of the good or service reduce the risk of utility assets being stranded to the detriment of ratepayers or otherwise provide benefits to ratepayers?

In coming to the conclusion that staff criteria three, five and six should not form a basis for its determinations, the Commission finds that it has jurisdiction to consider the impacts, either positive or negative, of the use of utility assets or services in the provision of goods to the downstream retail market, only with respect to utility ratepayers. If the new service is to be provided within the utility, the Commission will consider the appropriateness of this service within the mandate of the public utility.

5.1.4 Principles

Based on its analysis of the submissions, the Commission determines that principle six, that in all cases the Commission should consider the long-term effects on the markets of utility or related-NRB provision of unregulated goods and services, falls outside of its jurisdiction. Similarly, the Commission accepts that the principles must be revised to exclude references to considerations of customer choice. Accordingly, the Commission accepts that the following principles should govern the choice of corporate structure:

i) If a natural monopoly exists for the good or service, it should be provided as a regulated tariff item (Corporate Structure 1 in Figure 4).

ii) Utility participation in the unregulated downstream market by completely stand-alone NRBs using no utility resources is the preferred option since it provides the maximum protection to utility ratepayers (Corporate Structure 4 in Figure 4). Variations from this option should be undertaken only when it can be shown that this option would result in substantial stranded costs for the utility and/or that a transfer pricing policy mechanism will act to provide sufficient protection for ratepayers.

iii) The onus should always be on the utility to prove that the benefits associated with use of utility resources are sufficient to warrant the changed structure and that the transfer pricing policy mechanism will provide sufficient protection to ratepayers.

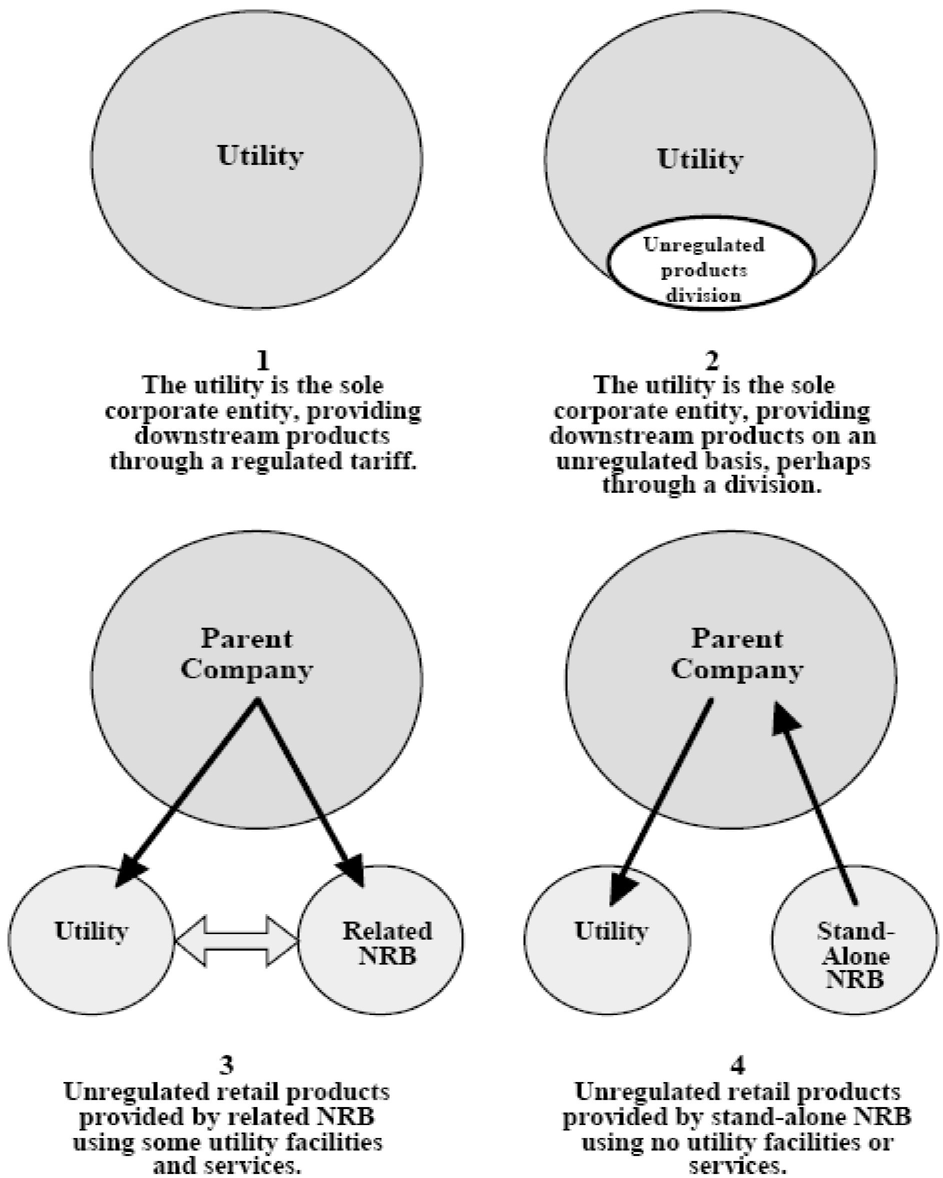
iv) If the Commission decides to allow the use of utility resources in the provision of the unregulated good or service, the preferred option is through a related-NRB (Corporate Structure 3 in Figure 4).

Direct participation by the utility in the provision of an unregulated good or service should be allowed only when the costs associated with forcing the provision through the related-NRB structure would significantly offset the benefits associated with the use of the utility's resources and it can be shown that a transfer pricing policy mechanism will provide sufficient protection for ratepayers (Corporate Structure 2 in Figure 4).

v) Utilities and their related-NRBs will be encouraged to move unregulated products which use utility resources into stand-alone NRBs as soon as market conditions warrant (Corporate Structure 4 in Figure 4). When a utility-provided product is moved to an NRB, the NRB will be required to pay fair market value to the utility for the assets, including goodwill, associated with the product. In addition, utilities will be required to provide periodic proof that the benefits associated with the use of utility services continue to exist and that ratepayers continue to be sufficiently protected. The Commission will make directions to prohibit the use of utility assets and services in the provision of goods and services downstream of the retail market at any time that it finds it in the interests of ratepayers to do so.

Figure 4

Potential Corporate Structures



(RMDM Guidlines, pp. 6, 21-24)

FORTISBC ENERGY INC.
TRANSFER PRICING POLICY FOR PROVISION OF UTILITY RESOURCES AND SERVICES, AUGUST 1997

Effective: OCT 16 1997 L-64-1997 BCUC Secretary: *Original signed by R.J. Pellatt*

{FortisBC Energy Inc.]
TRANSFER PRICING POLICY
For Provision of Utility Resources and Services August 1997

SCOPE

This policy addresses the pricing of resources and services provided by [FortisBC Energy Inc. (FortisBC Energy)] to:

- Non-Regulated Businesses (NRBs); and
- Divisions of the Utility providing unregulated products or services (collectively NRBs).

[FortisBC Energy Inc.] will ensure that it receives adequate compensation for the resources and services provided, thereby protecting ratepayers from subsidising unregulated activities.

The Transfer Pricing Policy will be used in conjunction with the [FortisBC Energy Inc.] Code of Conduct for Provision of Utility Resources and Services dated August, 1997. However, this policy does not replace [FortisBC Energy]/NRB contracts and undertakings in existence prior to approval of this Transfer Pricing Policy.

POLICY

Transfer Prices charged to NRBs by the Utility will ensure Utility ratepayers are not adversely affected and will be established using the following pricing rules.

1. Pricing Rules

i. If an applicable [FortisBC Energy] tariff rate exists, the Transfer Price will be set according to the tariff.

ii. Where no tariff rate exists, the Transfer Price will be set at either the full cost (see Section 2 below) or, where feasible and practical, the Competitive Market Price, whichever is greater.

iii. In situations where it can be shown that an alternative Transfer Price will provide greater benefits to the ratepayer, the Utility may apply to the Commission for special pricing consideration.

2. Determining Full Costs

For the purposes of this policy, costs for the resources or services being provided by the Utility to an NRB will be based on the Utility's full cost as described below. The definition of full costs will depend on the type of service or resource being provided.

For the most part the types of resources and services that can be provided to NRBs by the Utility are human resources and associated equipment and facilities. The example in Appendix A summarizes how full costs are determined for the different types of services described below in Section 2.1. The determination of full costs, specifically the cost loadings, is based on the approved Code of Business Conduct with respect to Non-Regulated Businesses of [FortisBC Energy] dated March 31, 1995, with modifications reflecting the types of resources and services involved in RMDM.

If other Utility resources or services are used by an NRB that are not described by this policy, then [FortisBC Energy] *will make an application to the Commission on a case-by-case basis. An example of this would be the determination of costs for a Utility asset permanently transferred to an NRB.*

2.1 Type of Service

There are three types of services: i. Specific Committed Service, ii. As Required Service and iii. Designated Subsidiary/Affiliate Service. It is important that the type of service is specified before the commencement of any service. This specification is to ensure that the correct cost loadings are applied to any Transfer Price.

i. **Specific Committed Service**

Specific Committed Service is work that is contracted for and billed regardless of whether or not work is actually performed. Typically, this work is ongoing or on a continuing basis (such as accounting) in support of NRB activities. The receiving organization (i.e. the NRB) is, in effect, requiring that the providing organization’s department (i.e. [FortisBC Energy]) maintain sufficient staffing levels throughout the year in order to provide this service. The receiving organization must pay for the Specific Committed Service even if the service is provided less than originally contracted.

It is important that the description and scope of the service to be provided be defined before the commencement of such a service, including an indication whether the service is performed at the employee’s normal place of work (“on-site”) or at the NRB’s (“offsite”). A request for Specific Committed Service may be raised or terminated at any time throughout the year. Termination of a Specific Committed Service as a result of an activity change is subject to a sixty (60) day notice period.

At the end of the fiscal year, Specific Committed Services which were not provided (unless the Utility was unable to meet its commitments) will be offset against services used in excess of those committed. Any excess service on a total pooled basis will be billed, but any deficiency will not be refunded. If there is a shortfall in the level of service provided by [FortisBC Energy] a reasonable refund may be made. In the normal course of business, the time estimates for Specific Committed Service are reviewed annually.

To determine the full cost of Specific Committed Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading and general overhead loading. Also facility and/or equipment charges are made if applicable. Appendix A, Column I shows an example of determining full cost for Specific Committed Service, both "on-site" and "off-site".

ii. **As Required Service**

As Required Service is work that is not specifically committed to by the receiving organization. The providing organization charges the cost of the actual time incurred to perform the work to the receiving organization. Typically, this is work that is not or cannot be budgeted in advance.

As Required Service must be specified to be either for an extended term (greater or equal to three months) or short term (less than three months) period prior to the commencement of the work. In addition, it must be identified whether the individual providing the services will work at his or her normal place of work ("on-site") or at the NRB's ("off-site").

To determine the full cost of As Required Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading, general overhead loading, supervision loading and an availability charge loading. Also facility and/or equipment charges are made if applicable. Appendix A, Column 2 shows an example of determining full cost for As Required Service.

In certain situations, the Utility will need to retain the immediate right to recall the employee being contracted to the NRB for an As Required Service. In these situations the availability charge will be waived. Prior notification to the Commission is required to waive the availability charge for As Required Service.

iii. **Designated Subsidiary/Affiliate Service**

A Designated Subsidiary/Affiliate is a related company that is designated by [FortisBC Energy] and approved by the Commission to receive reduced loadings in the Transfer Price. The designation relates to the additional benefits that the related company provides to [FortisBC Energy]'s customers, employees or to the economic development of the Province of British Columbia.

A Designated Subsidiary/Affiliate receives services on the same basis as the As Required Service described above. To determine the full cost of Designated Subsidiary/Affiliate Service, the following loadings are applied to direct labour costs: concessions loading, benefits loading and a general overhead loading. Appendix A, Column 3 shows an example of determining full cost for A Designated Subsidiary/Affiliate Service. The Commission may approve a subsidiary or affiliate with this status but exclude specific activities or projects of that subsidiary (e.g. projects taking place in certain geographic locations). Similarly, certain work to be performed for an NRB relating to a specific service, project or product may be designated by [FortisBC Energy] and approved by the Commission to receive reduced loadings.

3. Costs Relating to the Transfer of Activities from the Utility to NRB

3.1 Transfer Costs

Activities initially undertaken within the regulated Utility may, from time to time, be transferred to an NRB with Commission approval. Costs associated with transferring an activity to an NRB, and the start-up of NRB activities, shall be borne by the NRB. To the extent that these activities involve Utility resources during the transfer, the NRB shall reimburse the Utility using the appropriate pricing rules as defined in Section 1. Costs relating to the termination of an activity within the Utility shall be borne by the Utility.

3.2 Research Costs

As research is regarded as a continuing activity required to maintain the Utility's business and its effectiveness, such expenses shall be borne by the Utility. However, where it is evident that certain research activities are clearly directed towards specific non-regulated pursuits, the Utility will ensure it is compensated by the NRB according to the pricing rules defined in Section 1, net of any quantifiable benefits received by the Utility.

3.3 Development Costs

Development costs for new products and services transferred to an NRB will be tracked and charged to the NRB according to the pricing rules defined in Section 1, net of any quantifiable benefits received by the Utility.

4. Employment Issues

This section provides the guidelines which (FortisBC Energy) will follow in addressing the issues of employee transfers and human resource sharing between the Utility and NRBs. These guidelines implicitly recognize the fact that Utility ratepayers can realize significant benefits when employees have the opportunity to work for NRBs, by providing Utility employees with opportunities to expand their breadth of experience, enhance their skills and attributes, and continue their career development by taking advantage of the diversity of the (FortisBC Holdings Inc.) Organization.

Accordingly, it is not the intent of these guidelines to restrict employee transfers or human resource sharing, but rather to ensure that the benefits gained by employees can be brought back to the Utility and realized by ratepayers, and ratepayers are not negatively impacted. In all cases of Utility employee transfers or human resource sharing, the terms of transfers or sharing must be clearly understood by the Utility, NRB and the employee prior to commencement, and properly documented.

These guidelines distinguish between three distinct types of human resource issues: Rotational Transfers, Non-Rotational Transfers and Human Resource Sharing.

4.1 Rotational Transfers

Rotational Transfers represent a career training and development vehicle, in which employees are transferred between the Utility and an NRB on a full-time basis, for a period of time not to exceed 3 years. In these instances, the salary and associated benefits of the employee in question will be assumed by the NRB for the duration of the rotational transfer period. As this initiative is specifically intended as a career training and development mechanism with expected benefits back to the Utility, the individual will typically be assured of continued employment by the Utility at the conclusion of the transfer period.

4.2 Non-Rotational Transfers

Non-Rotational Transfers represent transfers of personnel between the Utility and an NRB, which are not subject to a maximum time duration. As neither the Utility nor its NRBs are required to provide preference to the other's employees in filling permanent positions, non-rotational transfers typically represent instances in which an employee has successfully responded to a posting or advertisement for a position.

In the interest of retaining qualified individuals within the [FortisBC Holdings Inc.] group of companies, and recognizing that many NRB companies already contract with the Utility for human resource services (including common payroll systems and benefits packages), a non-rotational transfer will typically be considered an employee transfer rather than a termination and re-employment. In this manner, employees will not be subjected to a termination of continued employment status and the Utility and NRB will not be required to assume the administrative burden associated with a termination and new hire process.

As a non-rotational transfer is not specifically classified as a career development and training initiative, there will typically be no assurance of employment security from the Utility, unless such assurance is considered to be in the best interest of the Utility, in which case a specific agreement should be negotiated and documented. Any recruitment or administrative costs associated with a non-rotational transfer will be borne by the entity to which the employee is transferring.

4.3 Human Resource Sharing

These guidelines specifically recognize that human resource sharing initiatives can provide a variety of benefits to the Utility and NRBs. For example, circumstances occasionally occur in which the Utility and one or more NRBs each require an individual with similar skills and attributes, but the time commitment required by each entity is insufficient to justify the hiring of a full-time person. In the absence of a human resource sharing initiative, each individual entity would likely be forced to incur the significant cost associated with securing the services of an external consultant, whereas significant cost savings could be realized by hiring an individual on a full-time basis and entering into a cost sharing arrangement. This cost sharing method may also pay future dividends to the Utility by developing in-house expertise and experience rather than developing this expertise and experience in consultants. Additionally, Utility departments or NRBs that are subject to large fluctuations in human resource requirements may have individuals that are not fully utilized at all times, but for whom termination and subsequent re-hire is not a viable option (e.g. due to uncertainty of future availability, termination costs, retraining costs, etc.). In these instances, human resource sharing provides a mechanism through which the receiving entity can fulfill short term resource demands with a qualified individual, while the employing entity can eliminate inefficient salary and benefit costs.

Human resource sharing initiatives also represent an ideal mechanism through which to realize some of the career development and training benefits associated with a rotational transfer, without having to commit to the absolute loss of an individual's services for a certain period of time.

These guidelines are predicated upon the assumption that although all of the applicable entities benefit from human resource sharing initiatives, the employing entity is assuming the greatest degree of risk due to the need to ensure continued employment or incur termination costs. Therefore, a key principle of the human resource sharing initiative proposed by [FortisBC Energy] is that the employing entity will always retain first rights on the services of the individual in question, assuming reasonable notice is provided to the entity for which the individual is providing services at a given point in time.

Employment costs, including salary and benefits, will be allocated to the various entities on a pro rata basis, in accordance with the number of hours dedicated to each entity, and in a manner consistent with the [FortisBC Energy] Code of Conduct for the Provision of Utility Resources and Services.

5. Cost Collection Procedures

5.1 Work Orders

The Utility will be responsible for setting up the appropriate work order, documenting the work order number and ensuring that the appropriate individuals charge time to it. The providing organization's accounting group (typically [FortisBC Energy]'s Financial Accounting Group) will be responsible for maintaining the work order and collecting the appropriate charges.

5.2 Time Sheets

The individuals performing the service must report all time spent on that service by coding their time to the appropriate work order numbers. This is to occur whether the type of service is Specific Committed, As Required or Designated Subsidiary/Affiliate Service. Time sheets are to be sent monthly to the immediate supervisor or [FortisBC Energy]'s Payroll Department. The NRB shall also review the validity of these time sheets.

5.3 Invoicing

The NRB will be invoiced for the contracted amount in respect of Specific Committed Service and for the appropriate time based on the actual payroll level in respect of As Required Service or Designated/Affiliate Service (subject to confidentiality of salary information) with the applicable loadings applied.

The methodology for determining a salary level is on the basis of the average pay grade in the case of Management and Exempt employees or the exact wage grade in the case of bargaining unit employees.

6. Accounting for Services

6.1 Detailed Operating & Maintenance Expense Forecast

In the event that [FortisBC Energy] makes an application to the Commission for revenues related to operations and maintenance expenses (O&M), time estimates for Specific Committed Services will need to be estimated or forecast for each of the years covered by the application. These estimates or forecasts should be consistent with the relevant costs and assumptions contained in that application.

In the event that an activity change causes a reduction in the actual level of the Specific Committed Service compared to the annual budget (or revenue requirement application), [FortisBC Energy] will use these amounts to offset additional contributions from the NRBs. Net contributions received by the Utility through Transfer Pricing for As Required Service and Designated Subsidiary/Affiliate will be held in a deferral account for future return to [FortisBC Energy]'s customers.

6.2 Operating & Maintenance Expense Forecast Determined by Formula

In the event [FortisBC Energy] makes a multi-year application to the Commission for revenues related to O&M, and the allowed O&M level is determined by means of a formula, for the duration of the test period and in accordance with the terms of the Commission Order G-85-97, [FortisBC Energy] will be entitled to capture the financial savings, such as cost reductions resulting from intercompany charges for RMDM or other NRB activities.

7. Review of Transfer Pricing Policy

The Transfer Pricing Policy will be reviewed on an annual basis as part of the Code of Conduct compliance review. However, [FortisBC Energy] may make application to the Commission for approval of changes to the policy including the pricing rules and the formula for determining full costs as and when required.

Terasen Gas Inc. Code of Conduct for Provision of Utility Resources and Services, August 1997

Effective: OCT 16 1997 L-64-1997
BCUC Secretary: *Original signed by R.J. Pellatt*

[Terasen Gas Inc.]

CODE OF CONDUCT

For Provision of Utility Resources and Services
August 1997

SCOPE

This Code of Conduct (Code) governs the relationships between [Terasen Gas Inc. (Terasen Gas)] and Non-Regulated Businesses (NRBs) for the provision of Utility resources, and conforms with the British Columbia Utilities Commission (Commission) "Retail Markets Downstream of the Utility Meter" (RMDM) Guidelines of April, 1997. The Commission Code of Conduct Principles from the Guidelines are attached as Appendix 'A'.

This Code will govern the use of Utility resources for unregulated activities (products or services for which there are no Commission approved tariffs) including shared services, employment or contracting of Utility personnel, and the treatment of customer, utility, or confidential information. The Code will also determine the nature of the relationship between the Utility and NRBs and the treatment by the Utility of its' NRBs.

The primary responsibility for administering this Code lies with [Terasen Gas], although the Commission has jurisdiction over matters referred to in this Code. The Commission acknowledges that the Utility in the administration of the Code may have to take into account particular circumstances in respect to a particular product or service which is being provided or transferred out of the Utility, and where these issues are at variance with this Code Commission approval will be required. The Code also provides that the Commission may review complaints in relation to the Code.

The [Terasen Gas] Transfer Pricing Policy, dated August 1997, will be used in conjunction with this Code to establish the costs and pricing for Utility resources and services.

This Code supersedes and replaces the [Terasen Gas] Code of Business Conduct dated March 31, 1995. However, this Code does not replace contracts and undertakings between [Terasen Gas] and NRB affiliates in existence prior to approval of the Code.

[Terasen Gas] Code of Conduct

DEFINITIONS

[Terasen Gas Inc.]	*May be abbreviated as follows: [Terasen Gas], the Utility, or the Company, and may also include employees of the Company.*
Commission	*British Columbia Utilities Commission.*
Guidelines	*Retail Markets Downstream of the Utility Meter Guidelines published by the British Columbia Utility Commission in April, 1997.*
Non-Regulated Business (NRB)	*An affiliate of the Utility not regulated by the Commission or a division of the Utility offering unregulated products and services. "Related NRB" refers to any NRB which is an affiliate of the Utility and which uses any resources of the Utility.*
Ratepayers	*Ratepayers in most cases are considered as a whole rather than one group or rate class.*
RMDM	*Acronym for "Retail Markets Downstream of the Utility Meter", which may include any utility or energy related activity at or downstream of the utility meter.*
Transfer Pricing	*The price established for the provision of Utility resources and services, or the transfer of Utility assets, to an NRB or division of the Utility providing unregulated products and services. Transfer pricing for any Utility resource or service will be determined by applying the [Terasen Gas] Transfer Pricing Policy approved by the Commission.*

APPLICATION OF COMMISSION PRINCIPLES

1. Transfer Pricing

The Utility will conform with the Commission approved [Terasen Gas] Transfer Pricing Policy.

2. Shared Services and Personnel

a) This Code recognizes the need for and potential benefits to the Utility of employee transfers and human resource sharing.

b) [Terasen Gas] may provide shared services to NRBs, including supervision and management, while ensuring that ratepayers will not generally be negatively impacted by Utility involvement. The costs of providing such services will be as agreed upon by both parties and be in accordance with the Commission approved [Terasen Gas] Transfer Pricing Policy.

c) NRBs may contract for any Utility personnel using the Commission approved [Terasen Gas] Transfer Pricing Policy, providing the Utility complies with Section 4 of this Code, Provision of Information by [Terasen Gas Inc.], and no conflict of interest exists which will negatively impact on ratepayers.

3. Transfer of Assets or Services

The price for all transfers of assets or services shall be determined in accordance with the [Terasen Gas] Transfer Pricing Policy approved by the Commission, and the Utility must be able to demonstrate that the benefits to the ratepayer are greater than the cost. The transfer price will reflect the potential for risk (stranded assets, future costs, etc.) and the recall availability of shared or transferred personnel to ensure the Utility receives the appropriate benefit from expertise resident in the Utility. [Terasen Gas] will comply with acceptable business practices if it wishes to purchase assets, goods or services from an NRB.

An appropriate allocation of development costs for products or services as defined in the [Terasen Gas] Transfer Pricing Policy, will be included in the transfer price.

4. Provision of Information by [Terasen Gas Inc.]

[Terasen Gas] will not provide to an NRB any information that would inhibit a competitive energy services market from functioning.

The following should act as a guideline for employees confronted with issues related to the sharing of confidential information:

a) This Code precludes [Terasen Gas] from releasing confidential customer specific information without the consent of that customer. If a customer agrees to a general release of customer specific information, that information must be made available to any market participant who requests it and is willing to pay costs associated with the provision of the information, without discrimination as to access, timing, cost or content. If a customer requests customer specific information be provided to a specific market participant, only that participant may receive the information, subject to payment of associated costs incurred to provide the information.

b) [Terasen Gas] may disclose to any market participant that requests it and is willing to pay the appropriate transfer price customer information that is aggregated or summarized in such a way that confidential information would not ordinarily be ascertained by third parties.

c) [Terasen Gas] may provide or sell any non-customer specific information to any market participant that requests it and is willing to pay the appropriate transfer price.

5. <u>Preferential Treatment</u>

[Terasen Gas] will not state or imply that favoured treatment will be available to customers of the Utility as a result of using any service of an NRB. In addition, no Company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the Company as a result of using any product or service of an NRB.

6. <u>Equitable Access to Services</u>

Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, [Terasen Gas] will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer.

7. <u>Compliance and Complaints</u>

a) [Terasen Gas] will advise all of its employees of their expected conduct pertaining to this Code, with annual updates for employees who may be directly involved with NRB activities.

b) [Terasen Gas] will monitor employee compliance with this Code by conducting an annual compliance review, the results of which will be summarized in a report to be filed with the Commission within 60 days of the completion of this review.

c) Complaints by third parties about the application of this Code, or any alleged breach thereof, should be addressed in writing to the Company's [Vice-President, Finance & Regulatory Affairs], who will bring the matter to the immediate attention of the Company's senior management and promptly initiate an investigation into the complaint. The complainant, along with the Commission, will be notified in writing of the results of the investigation, including a description of any course of action which will be or has been taken promptly following the completion of the investigation. The Company will endeavour to complete this investigation within 30 days of the receipt of the complaint.

d) Where [Terasen Gas] determines that the complaint is unfounded, the Company may apply to the Commission for reimbursement of the costs of the investigation from the third party initiating the complaint or where this is not possible, for inclusion of those costs in rates.

8. Financing and Other Risks

[Terasen Gas] will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by [Terasen Gas] for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.

9. Use of Utility Name

[Terasen Gas Inc.] agrees that newly established NRBs engaging in RMDM activities will not use the Utility's name as the primary identifier within British Columbia, and will not use the Utility name in a manner that indicates that Utility resources will support the NRB.

10. Distribution System Access

[Terasen Gas] will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and in accordance with the requirements approved for direct commodity marketing in British Columbia.

11. Amendments

In order to ensure that this Code remains workable and effective, the Company will review the provisions of this Code on an ongoing basis and as required by the Commission, but with a maximum of three years between reviews.

Amendments to this Code may be made from time to time as approved by the Commission.

Appendix 'A'

COMMISSION CODE OF CONDUCT PRINCIPLES

The Commission has established the following principles in the Guidelines which [Terasen Gas] intends to apply to RMDM activities and the Utility's relationships with NRBs.

i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to a release of customer information to the NRB, it should be provided to other market participants under the same terms and conditions and for the same price. Should an individual customer make a specific request to have information released to a particular third party, it will be released to that party only. The utility will be able to recover from the customer the costs associated with the provision of this information.

ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB. In addition, no regulated company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the company as a result of using any service of an NRB.

iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB. If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.

iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles. These audits will be performed no less than once a calendar year and filed with the Commission.

v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission. The report will be filed with the Commission within one month of the complaint being made.

vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity. No cross-guarantees or any form of financial assistance whatsoever should be provided directly or indirectly by a utility to its NRB without approval of the Commission.

vii) Use of the utility name by a related NRB will require approval by the Commission to ensure that its use will not interfere with the Commission's ability to protect ratepayers.

In those cases where retail customers have direct market access to the commodity, the utility's code of conduct will also include the following provision,

> The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

IN THE MATTER OF

the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Inquiry into FortisBC Energy Inc.
regarding the Offering of Products and Services in
Alternative Energy Solutions and Other New Initiatives

EXHIBIT LIST

COMMISSION DOCUMENTS

A-1	Letter and order G-95-11 dated May 24, 2011 – Procedural Conference Notice and Timetable
A-2	Letter dated May 25, 2011 – Appointment of Commission Panel
A-3	Letter dated June 13, 2011 – Additional member of the Panel
A-4	Letter dated June 14, 2011 – Agenda for the Procedural Conference on June 15, 2011
A-5	Letter dated July 8, 2011 – Order G-118-11 Scope of Issues, Reasons for Decision, Terms of Reference, Regulatory Timetable
A-6	Letter dated September 16, 2011 – Commission Information Request No. 1
A-7	Letter dated September 20, 2011 – Request for Comments regarding Amendments to Regulatory Timetable
A-8	Letter dated September 23, 2011 – Order G-164-11 issuing Amended Regulatory Timetable
A-9	Letter dated June 13, 2011 – Procedural Information to Participants NOTE: Was Exhibit A3-1 was mis-allocated renamed as Exhibit A-9
A-10	Letter dated December 6, 2011 – Letter L-91-11 issuing Amended Regulatory Timetable
A-11	Letter dated December 9, 2011 – Information Request No. 1 to CEF
A-12	Letter dated December 9, 2011 – Information Request No. 1 to CRNG
A-13	Letter dated December 9, 2011 – Information Request No. 1 to Corix

A-14 Letter dated December 9, 2011 – Information Request No. 1 to ESAC

A-15 Letter dated December 16, 2011 – Information Request No. 1 to Ferus

A-16 Letter dated January 3, 2012 – PACA Budget Estimates

A-17 Letter dated January 4, 2011 – Order G-1-12 and Reasons for Decision establishing a written comment process on the threshold for CPCNs for AES and other New Initiatives projects

A-18 Letter dated January 19, 2012 – Response to Registered Interveners regarding filing extension request by ESAC

A-19 Letter dated January 24, 2012 – Procedural Conference No. 2 Agenda and Proposed Regulatory Timetables A, B and C

A-20 Letter dated January 31, 2012 – Order G-9-12 and Reasons for Decision establishing Format of Inquiry Proceeding and Regulatory Timetable

A-21 Letter dated February 6, 2012 - Information Request No. 2 to FEI

A-22 Letter dated February 9, 2012 – Issuing Final Submission Guidelines

A-23 Letter dated March 8, 2012 – Response to FEU Letter dated March 2, 2012

A-24 Letter dated March 12, 2012 – Issuing Excerpt from the Commission Decision on FEI's Application for a CPCN in respect of thermal energy service to Delta School District No. 37

A-25 Letter dated May 3, 2012 – Issuing Notice for Oral Hearing not required

COMMISSION STAFF DOCUMENTS

A2-1 Letter dated May 25, 2011 – Commission Staff filing Energy Services Association of Canada application dated April 27, 2011

A2-2 Letter dated May 25, 2011 – Commission Staff filing Corix Utilities May 6, 2011 letter supporting the Energy Services Association of Canada April 27, 2011 Application

A2-3 Letter dated September 16, 2011 - Commission Staff filing Community Energy Association, Renewable Energy Guide for Local Governments in BC: Utilities & Financing module, February 2008

A2-4	Letter dated September 16, 2011 - Commission Fraser Basin Council Community Energy Planning: Policies and Tools Presentation
A2-5	Letter dated September 16, 2011 - Commission Staff filing BC Hydro Featured Projects (BC Hydro webpage)
A2-6	Letter dated September 16, 2011 - Commission Staff filing Ontario Power Authority District Energy Research Report Briefing Note
A2-7	Letter dated September 16, 2011 - Commission Staff filing Con Edison Steam Long Range Plan 2010-2030
A2-8	Letter dated September 16, 2011 - Commission Staff filing Con Edison 2010 Annual Report Excerpt
A2-9	Letter dated September 16, 2011 - Commission Staff filing TerraSource Geothermal Utility Provider (TerraSource webpage)
A2-10	Letter dated September 16, 2011 – Commission Staff filing GeoTility Commercial Projects (GeoTility webpage)
A2-11	Letter dated September 16, 2011 - Commission Staff filing City of Surrey Gas Stations and Alternative Fuel Source Press Release May 30, 2011
A2-12	Letter dated September 16, 2011 - Commission Staff filing Californian Public Utilities Commission Affiliate Rules D9809035
A2-13	Letter dated September 16, 2011 - Commission Staff filing FortisBC CDEA-IDEA Integrated Energy Solutions Presentation June 2011
A2-14	Letter dated September 16, 2011 - Commission Staff filing Alberta EUB Decision 2003-040: ATCO Group Inter-Affiliate Code of Conduct
A2-15	Letter dated September 16, 2011 - Commission Staff filing FortisAlberta Inc. Inter-Affiliate Code Of Conduct (and copy of webpage source)
A2-16	Letter dated September 16, 2011 - Commission Staff filing TGI 2010-11 RRA Attachment C-27 Alternative Energy System Cost of Service
A2-17	Letter dated September 16, 2011 - Commission Staff filing Californian Public Utilities Commission Rulemaking regarding Affiliates D9712088
A2-18	Letter dated September 16, 2011 - Commission Staff filing Terasen Energy Services Inc. Waterstone Pier Case-study

A2-19	Letter dated September 16, 2011 - Commission Staff filing Ontario Energy Board Enbridge Gas Distribution Inc. Decision EB2009-0172
A2-20	Letter dated September 16, 2011 - Commission Staff filing Gaz Métro Corporate Structure (Gaz Métro webpage)
A2-21	Letter dated September 16, 2011 - Commission Staff filing ÉBI Énergie Green Natural Gas Service (ÉBI Énergie webpage)
A2-22	Letter dated September 16, 2011 - Commission Staff filing Terasen Energy Services Inc. Press Release November 3 2008
A2-23	Letter dated December 9, 2011 – Commission Staff filing City of Coquitlam, bclocalnews.com report – dated November 18, 2011
A2-24	Letter dated December 9, 2011 – Commission Staff filing City of Coquitlam Committee Memo – dated October 18, 2011
A2-25	Letter dated December 9, 2011 – Commission Staff filing OFGEM RIIO: A new way to regulate energy networks, Final Decision – dated October 2010
A2-26	Letter dated December 9, 2011 – Commission Staff filing Canadian Radio-television and Telecommunications Commission Decision 94-19 Review of Regulatory Framework – dated September 16, 1994
A2-27	Letter dated December 9, 2011 – Commission Staff filing Illinois 1998 Rulemaking on Non-Discrimination in Affiliate Transactions for Electric Affiliates
A2-28	Letter dated February 6, 2012 - Commission Staff filing The Economics of Regulation – Principles and Institutions, Alfred E. Kahn
A2-29	Letter dated February 6, 2012 - Commission Staff filing Whom Does the Regulatory Commission of Alaska Regulate?" - Dated September 1, 2007
A2-30	Letter dated February 6, 2012 - Commission Staff filing Competition Bureau Canada – Canadian Competition Law Roles, Responsibilities and Relations in Emerging Electricity Markets – Dated September 20-21, 2001
A2-31	Letter dated February 6, 2012 - Commission Staff filing The American Economic Review – Behavior of the Firm Under Regulatory Constraint, H. Averch and L. L. Johnson – Dated December 1962

A2-32	Letter dated February 13, 2012 – Commission Staff filing B.C. Sustainable Energy Association January 31, 2012, letter regarding the status of the FortisBC Energy Inc. Compressed Natural Gas Service/Liquefied Natural Gas General Terms and Conditions Section 12B
A2-33	Letter dated February 13, 2012 – Commission Staff filing FortisBC Energy Inc. February 1, 2012, letter in response to B.C. Sustainable Energy Association January 31, 2012 letter inquiring on the status of the FortisBC Energy Inc. Compressed Natural Gas Service/Liquefied Natural Gas General Terms and Conditions Section 12B
A2-34	Letter dated February 13, 2012 – Commission Staff filing BCUC February 2, 2012, letter in response to BCSEA January 31, 2012 letter inquiring on the status of the FortisBC Energy Inc. for Compressed Natural Gas Service/Liquefied Natural Gas General Terms and Conditions Section 12B
A2-35	Letter dated February 13, 2012 – Commission Staff filing BCUC Order G-14-12 dated February 7, 2012, approving Section 12B of FortisBC Energy Inc.'s General Terms and Conditions
A3-1	Removed September 29, 2011 – Exhibit was mis-allocated renamed as Exhibit A-9

FEU DOCUMENTS

B-1	**FORTISBC ENERGY UTILITIES (FEU)** Letter dated June 9, 2011 – Submission regarding the scope of the Inquiry and Exhibit Book
B-2	Letter dated August 29, 2011 – FEU Submitting Evidence
B-3	Letter dated September 19, 2011 – FEU Submitting Request to Amend Regulatory Timetable
B-4	Letter dated September 22, 2011 – FEU Submitting Proposed Regulatory Timetable
B-5	Letter dated November 3, 2011 - FEU Response to BCOAPO Information Request No. 1
B-6	Letter dated November 3, 2011 - FEU Response to BCSEA Information Request No. 1
B-7	Letter dated November 3, 2011 - FEU Response to CEC Information Request No. 1
B-8	Letter dated November 3, 2011 - FEU Response to Corix Information Request No. 1

B-9	Letter dated November 3, 2011 - FEU Response to ESAC Information Request No. 1
B-10	Letter dated November 3, 2011 - FEU Response to Ferus Information Request No. 1
B-11	Letter dated November 3, 2011 - FEU Response to BCUC Information Request No. 1
B-11-1	**CONFIDENTIAL** Letter dated November 3, 2011 - FEU CONFIDENTIAL Response to BCUC Information Request No. 1
B-12	Letter dated December 9, 2011 – FEU Submitting Information Request No. 1 to CEF
B-13	Letter dated December 9, 2011 – FEU Submitting Information Request No. 1 to CRNG
B-14	Letter dated December 9, 2011 – FEU Submitting Information Request No. 1 to ESAC
B-15	Letter dated December 9, 2011 – FEU Submitting Information Request No. 1 to Corix
B-16	Letter dated December 19, 2011 –FEU Submitting Information Request No. 1 to FI
B-17	Letter dated January 16, 2012 – FEU Submissions regarding the CPCN threshold
B-18	Letter dated January 18, 2012 – FEU Submitting Notice of Late Filing regarding Rebuttal Evidence
B-19	Letter dated January 19, 2012 – FEU Submitting Rebuttal Evidence
B-20	Letter dated January 20, 2012 – FEU Submissions on the Format of the Proceeding
B-21	Letter dated January 23, 2012 – FEU Submissions Regarding Interim CPCN Threshold
B-22	Letter dated February 7, 2012 - FEU Submitting BC Natural Gas Strategy - Ministry of Energy and Mines
B-23	Letter dated February 7, 2012 - FEU Submitting BC LNG Strategy - Ministry of Energy and Mines
B-24	Letter dated February 10, 2012 - FEU Submitting Response to Ferus Exhibit C8-12
B-25	Letter dated February 13, 2012 - FEU Submitting Response to BCUC IR No. 2

INTERVENER DOCUMENTS

C1-1	**ENERGY SERVICES ASSOCIATION OF CANADA (ESAC)** Letter Dated June 1, 2011 Via Email – Request for Intervener Status by Karl Gustafson and Ronald Cliff
C1-2	Letter Dated June 9, 2011- ESAC Submission regarding scope and process
C1-3	Letter dated September 16, 2011 - ESAC Submitting Information Request No. 1
C1-4	Letter dated September 21, 2011 – ESAC Submitting Comments regarding Amendments to Regulatory Timetable
C1-5	Letter dated November 21, 2011 – ESAC Submitting evidence
C1-6	Letter dated December 23, 2011 – ESAC Response to BCUC Information Request No. 1
C1-7	Letter dated December 23, 2011 – ESAC Response to CEC Information Request No. 1
C1-8	Letter dated December 23, 2011 – ESAC Response to BCOAPO Information Request No. 1
C1-9	Letter dated December 23, 2011 – ESAC Response to BCSEA Information Request No. 1
C1-10	Letter dated December 23, 2011 – ESAC Response to FEU Information Request No. 1
C1-11	Letter dated January 16, 2012 – ESAC Submissions regarding the CPCN threshold
C1-12	Letter dated January 18, 2012 – ESAC Submissions regarding FEU Late Filing of Rebuttal Evidence
C1-13	Letter dated January 23, 2012 – ESAC Submissions on the Format of the Proceeding
C2-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CEC) VIA EMAIL** Letter Dated June 6, 2011- Request for Intervener Status by Christopher Weafer
C2-2	Letter Dated June 9, 2011 –CEC submitting Comments on Issues, Scope and Process and confirmation on attending the procedural conference
C2-3	Letter dated September 16, 2011 - CEC Submitting Information Request No. 1

C2-4	Letter dated September 22, 2011 – CEC Submitting Comments regarding Amendments to Regulatory Timetable
C2-5	Letter dated December 9, 2011 – CEC Submitting Information Request No. 1 to Corix
C2-6	Letter dated December 9, 2011 – CEC Submitting Information Request No. 1 to ESAC
C2-7	Letter dated December 19, 2011 –CEC Submitting Information Request No. 1 to FI
C2-8	Letter dated January 23, 2012 – CEC Submissions on the Format of the Proceeding
C3-1	**CITY OF KAMLOOPS (CK)** Online Registration Dated June 7, 2011 - Request for Intervener Status by Jen Fretz
C4-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB BRITISH COLUMBIA (BCSEA)** Letter and Online Registration dated June 8, 2011 – Request for Intervener Status by William J. Andrews and Thomas Hackney
C4-2	Letter dated September 16, 2011 - BCSEA Submitting Information Request No. 1
C4-3	Letter dated September 21, 2011 - BCSEA Submitting Comments regarding Amendments to Regulatory Timetable
C4-4	No Exhibit
C4-5	Letter dated December 9, 2011 – BCSEA Submitting Information Request No. 1 to CEF
C4-6	Letter dated December 9, 2011 – BCSEA Submitting Information Request No. 1 to FI
C4-7	Letter dated December 9, 2011 – BCSEA Submitting Information Request No. 1 to Corix
C4-8	Letter dated December 9, 2011 – BCSEA Submitting Information Request No. 1 to ESAC
C4-9	Letter dated January 16, 2012 – BCSEA Submissions regarding the CPCN threshold
C4-10	Letter dated January 20, 2012 – BCSEA Submissions on the Format of the Proceeding
C4-11	Letter dated January 20, 2012 – BCSEA Submitting Comments regarding the CPCN threshold

C5-1	**PACIFIC NORTHERN GAS LTD (PNG)** Online Registration dated June 8, 2011 – Request for Intervener Status by Craig Donohue
C6-1	**BOARD OF EDUCATION OF SCHOOL DISTRICT NO. 37 DELTA (BESD)** Online Registration dated June 8, 2011 – Request for Intervener Status by Frank Geyer
C7-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration dated June 9, 2011 – Request for Intervener Status by Janet Fraser
C7-2	Letter Dated June 9, 2011 –BCH submitting Comments on Issues, Scope and Process and confirmation on attending the procedural conference
C8-1	**FERUS INC. (FI))** Online Registration dated June 9, 2011 – Request for Intervener Status by Nick Gretener and Sean Lalani
C8-2	Letter Dated June 9, 2011 –FI submitting Comments on Issues, Scope and Process and notice of not attending the procedural conference
C8-3	Letter Dated September 16, 2011 – FI Submitting Information Request No. 1
C8-4	Letter dated September 21, 2011 - FI Submitting Comments regarding Amendments to Regulatory Timetable
C8-5	Letter dated December 2, 2011 - FI Submitting Request to File Late Evidence
C8-5-1	Letter dated December 2, 2011 - FI Submitting Evidence
C8-6	Letter dated December 23, 2011 – FI Response to FEU Information Request No. 1
C8-7	Letter dated December 23, 2011 – FI Response to BCUC Information Request No. 1
C8-8	Letter dated December 23, 2011 – FI Response to CEC Information Request No. 1
C8-9	Letter dated December 23, 2011 – FI Response to BCSEA Information Request No. 1
C8-10	Letter dated January 16, 2012 – FI Submissions regarding the CPCN threshold
C8-11	Letter dated January 23, 2012 – FI Submissions on the Format of the Proceeding
C8-12	Letter dated February 10, 2012 – FI Comments on FortisBC letter from February 1, 2012
C9-1	**QUEST (QUEST)** Online Registration dated June 9, 2011 – Request for Intervener Status by Richard Laszlo

C10-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION (BCOAPO) VIA EMAIL** Letter Dated June 8, 2011 – Request for Intervener Status by Leigha Worth and James Wightman and confirmation on attending the procedural conference
C10-2	Letter dated September 16, 2011 - BCOAPO Submitting Information Request No. 1
C10-3	Letter dated September 16, 2011 - BCOAPO Submitting update to contact information
C10-4	Letter dated September 20, 2011 - BCOAPO Submitting Comments regarding Amendments to Regulatory Timetable
C10-5	Letter dated January 16, 2012 – BCOAPO Submissions regarding the CPCN threshold
C10-6	Letter dated January 23, 2012 – BCOAPO Submissions on the Format of the Proceeding
C11-1	**GREATER VANCOUVER HOME BUILDERS' ASSOCIATION (GVHBA)** Online Registration dated June 9, 2011 – Request for Intervener Status by Peter Simpson
C12-1	**CORIX UTILITIES INC (CORIX)** Letter Dated June 9, 2011 – Request for Intervener Status by Ian Wigington and David Bursey
C12-2	Letter Dated June 15, 2011 – Corix submitting summary
C12-3	Letter dated September 16, 2011 - Corix Submitting Information Request No. 1
C12-4	Letter dated September 22, 2011 – Corix Submitting Comments regarding Amendments to Regulatory Timetable
C12-5	Letter dated November 21, 2011 – Corix Submitting evidence
C12-6	Letter dated November 22, 2011 – Corix Submitting further evidence
C12-7	Letter dated December 23, 2011 – Corix Response to BCUC Information Request No. 1
C12-7-1	Errata dated January 7, 2012 to Corix Response to BCUC Information Request No. 1
C12-8	Letter dated December 23, 2011 – Corix Response to BCSEA Information Request No. 1
C12-8-1	Errata dated January 7, 2012 to Corix Response to BCSEA Information Request No. 1

C12-9	Letter dated December 23, 2011 – Corix Response to CEC Information Request No. 1
C12-10	Letter dated December 23, 2011 – Corix Response to FEU Information Request No. 1
C12-10-1	Errata dated January 7, 2012 to Corix Response to FEU Information Request No. 1
C12-11	Letter dated January 16, 2012 – Corix Submissions regarding the CPCN threshold
C12-12	Letter dated January 23, 2012 – Corix Submissions on the Format of the Proceeding
C13-1	**MINISTRY OF ENERGY AND MINES (MEM)** Letter Dated June 9, 2011 – Request for Intervener Status by Jennifer Champion and submitting Comments on Issues, Scope and Process, confirmation on attending the procedural conference
C13-2	Letter dated September 22, 2011 – MEM Submitting Comments regarding Amendments to Regulatory Timetable
C14-1	**PCI DEVELOPMENTS (PCI))** Online Registration dated June 9, 2011 – Request for Intervener Status by Brennan Cook
C15-1	**URBAN DEVELOPMENT INSTITUTE (UDI)** Online Registration dated June 27, 2011 – Request for Late Intervener Status by Jeffrey Fisher
C16-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter Dated September 14, 2011 – Request for Late Intervener Status by Jim Quail
C16-2	Letter dated January 19, 2012 – COPE 378 Submitting Comments on Regulatory Process
C17-1	**CLEAN ENERGY FUELS (CEF)** Letter dated September 14, 2011 – Request for Late Intervener Status by Brian Powers
C17-2	Letter dated November 21, 2011 – CEF Submitting evidence
C17-3	Letter dated December 23, 2011 – CEF Response to FEU Information Request No. 1
C17-4	Letter dated January 4, 2012 – CEF Response to BCUC and BCSEA Information Requests No. 1
C17-5	Letter dated January 16, 2012 – CEF Submissions regarding the CPCN threshold
C17-6	Letter dated January 20, 2012 – CEF Submissions on the Format of the Proceeding
C17-7	Letter dated February 10, 2012 - CEF Submitting Comments

C18-1	**COALITION FOR RENEWABLE NATURAL GAS (CRNG)** Letter dated November 3, 2011 – Request for Late Intervener Status by Johannes Escudero and David Cox
C18-2	Letter dated November 21, 2011 – CRNG Submitting evidence
C18-3	Letter dated December 14, 2011 – CRNG Response to FEU Information Request No. 1
C18-4	Letter dated December 22, 2011 – CRNG Response to BCUC Information Request No. 1
C19-1	**THERMAL ENVIRONMENTAL COMFORT ASSOCIATION (TECA)** Letter dated November 18, 2011 – Request for Late Intervener Status by Kim Savage
C20-1	**ARTEX BARN SOLUTIONS (ABS)** Online Registration Dated January 19, 2012 – Request for Late Intervener Status by John de Jonge

INTERESTED PARTY DOCUMENTS

D-1	**CENTRAL HEAT DISTRIBUTION LTD (CHD)** Letter Dated May 30, 2011 - Request for Interested Party Status by John Barnes
D-2	**ALTAGAS UTILITIES INC (ALTAGAS)** Online Registration Dated June 6, 2011 - Request for Interested Party Status
D-3	**ENBRIDGE GAS DISTRIBUTION INC (EGD)** Online Registration Dated June 7, 2011 - Request for Interested Party Status by Lesley Austin
D-4	**BC TRANSIT (BCT) VIA FAX** Received June 9, 2011 – Request for Interested Party Status by Brian Anderson
D-5	**CITY OF VANCOUVER (CV)** Online Registration Dated June 10, 2011 - Request for Interested Party Status by Chris Baber
D-6	**CANADIAN DISTRICT ENERGY ASSOCIATION (CDEA)** Online Registration dated June 11, 2011 – Request for Interested Party Status by Mary Richardson
D-7	**ACTIVE RENEWABLE (BC)** – Online Registration dated July 14, 2011 – Request for Interested Party Status by Bill Daly
D-8	**BELANGER, CLARE** – Letter dated July 6, 2011 – Request for Interested Party Status and Letter of Comment

D-9 **HONEYWELL BUILDING SOLUTIONS (HBS)** Online Registration dated November 22, 2011 – Request for Interested Party Status by Donald Thibodeau

D-9-1 Letter dated November 22, 2011 – HBS Submitting letter of comment

D-10 **HEATING, REFRIGERATION AND AIR CONDITIONING INSTITUTE OF CANADA (HRACIC)** Online Registration dated December 6, 2011 - Request for Interested Party Status by Martin Luymes

D-11 **JOHNSON CONTROLS CANADA LP (JCCLP)** Letter and Online Registration dated December 8, 2011 - Request for Interested Party Status by Stuart Morrow and Letter of Comment

SUMMARY OF DIRECTIVES, DETERMINATIONS AND RECOMMENDATIONS

Biomethane Service

Directives:

1. Biomethane Service is part of FEU's regulated service offering.

2. Biomethane Service is a Separate Class of Customer within the natural gas class of service.

3. Biomethane upgraders are similar in function to provincial gas plants and are regulated under the *UCA*.

4. Biomethane upgraders and the pipe connecting them to the traditional distribution utility are not extensions of the utility system as contemplated in sections 45(1) and (2) of the *UCA*.

5. The $5 million CPCN Threshold for Biomethane Projects is maintained.

Recommendations:

a. Future Commission Panels will be required to assess the form of regulation to be imposed on biomethane upgraders, including the possibility of a section 88.3 exemption.

b. The addition of the pipe from the biomethane ugrader to the utility system should be reviewed on a case-by-case basis.

c. The Panel reviewing the Biomethane Post Implementation Report relating to the existing Biomethane pilot project may wish to establish rules or parameters covering pipeline connections to upgraders.

d. Regarding ownership of biomethane upgraders, it is recommended FEU not own upgrading facilities where viable options exist but it the case in does, the upgrader should be owned and operated in an Affiliated Regulated Business and biogas supplied to FEI under a section 71 contract.

CNG Activities

Directives:

1. CNG Service is regulated when undertaken by a public utility but is not regulated otherwise.

2. CNG activities undertaken as Prescribed Undertakings, are to be structured as a Separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit.

3. No CPCN is required for CNG Service as a Prescribed Undertaking and for CNG activities undertaken by non-public utility providers. For all other CNG Service to be provided by a public utility, a CPCN is required.

4. A $0 CPCN Threshold is set for CNG activities undertaken by the FEU or any other public utility outside the Prescribed Undertaking.

Recommendations:

a. The FEU undertake CNG activities outside the Prescribed Undertaking in a Non-Regulated Business.

b. Future Commission Panels may wish to consider whether the CNG market has, in fact, been kick started and whether projects in FEU's CNG Class of Service should be transferred to a Non-Regulated Business.

LNG Activities

Directives:

1. LNG Service is regulated when undertaken by a public utility but is not regulated otherwise.

2. LNG activities undertaken as Prescribed Undertakings are to be maintained as a Separate Class of Service with the costs recoverable from the traditional natural gas ratepayer.

3. No CPCN is required for LNG activities undertaken as Prescribed Undertakings. A $0 CPCN Threshold is set for LNG activities undertaken by the FEU or any other public utility outside the Prescribed Undertaking.

Recommendations:

a. FEU participate in LNG activities outside the Prescribed Undertaking through a separate Non-Regulated Business.

b. In all cases, if FEU have excess capacity to supply LNG and/or tanker service, the FEU should supply that LNG at the higher of the market price or the fully allocated cost of service.

c. Future panels may wish to consider whether the LNG market has, in fact, been kick started and whether projects in FEU's Class of Service should be transferred to a Non-Regulated Business.

Thermal Energy Services

Directives and Determinations:

1. Thermal Energy Services are regulated under the *UCA.*
2. The $0 CPCN Threshold for TES Projects is maintained.
3. TES comprise a fundamentally different line of business, occurring beyond the gas distribution meter, and cannot therefore be considered an extension of the utility distribution system.
4. Commission Staff will conduct consultation on a scaled regulatory framework for TES utilities. The resulting framework will be brought to the Commission for approval.

Recommendations:

a. Until such time as the *UCA* is amended, exemptions from regulation should be sought for Discrete Energy Systems with no monopoly characteristics or need for consumer protection. Where such exemptions are granted it would be appropriate for FEU to pursue Discrete Energy Systems through a stand-alone Non-Regulated Business that is separate from the traditional gas distribution utility.

b. TES Projects (that are not exempt from regulation) are most appropriately undertaken through an Affiliated Regulated Business.

Other Findings and Determinations:

1. CPCN Thresholds, where appropriate, will apply equally to all parties.

2. The costs of this hearing are to be allocated 75 percent to FEU's natural gas customer and 25 percent to FEU's Thermal Energy Services customers.

3. FEI is to file an application for the allocation and recovery of the Thermal Energy Services Deferral Account as set out in the attached Report.

4. The FEU are directed to bring forward a proposal for mechanisms for approval and administration of DSM and other incentive funds by a neutral third party where there is a potential for FEU to benefit, either directly or indirectly, from that funding.

5. FEI, and, where applicable, all other regulated public utilities, are directed to comply with all the directives of the Commission set out in the Inquiry Report issued concurrently with this Order.

Other Recommendations:

a. The FEU should initiate a process to prepare an updated Code of Conduct and Transfer Pricing Policy in respect of the interaction between the regulated utility and related Non-Regulated Businesses, as per the further recommendations set out in the attached Reasons for Decision.

b. The FEU should undertake a collaborative process to establish a Code of Conduct and Transfer Pricing Policy governing the interactions between affiliated regulated businesses consistent with the Principles and Guidelines set out in the attached Report.

c. The FEU and other utilities considering a new business activity should follow the example provided by the Biomethane Service Introduction in any future applications.

d. Sharing of services among affiliates should be done on the basis of the higher of market pricing or the fully allocated cost in accordance with the Principles and Guidelines and an approved Code of Conduct and Transfer Pricing Policy.

e. The FEU should file an application with the Commission to revise General Terms and Conditions 12B to reflect the findings of the Inquiry Report.

f. No further applications should be brought forward by FEI based on General Terms and Conditions 12A. FEI/FAES should review GT&C 12A to determine if it can be eliminated or requires amendment, and bring the results of this review to the Commission for approval.

g. Fortis Alternative Energy Services should bring a general thermal tariff to the Commission for review and approval following the approval of the regulatory framework for TES utilities.

h. The *Utilities Commission Act* should be amended to:

   i. exclude regulation of activities where competitive forces are found to provide sufficient protection to the public.

   ii. allow the Commission to forebear from regulating where it finds there is no monopoly or need for consumer protection.