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The Regulation of *District Energy* Systems

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EXECUTIVE SUMMARY

District energy systems are promoted as a way to provide low carbon heat and hot water. In British Columbia, most systems are "public utilities" and regulated by the BC Utilities Commission (BCUC) unless the services are provided by a local government.

This paper examines nine diverse systems, four under BCUC jurisdiction and five regulated by municipalities, to elicit the type and level of economic regulation that can encourage financial sustainability while providing customers with reasonably priced energy services.

DE systems can have a number of environmental and community advantages, and, if properly designed, constructed and regulated can be cost effective.

Nonetheless, proponents need to appreciate the plethora of risks associated with any start-up utility. DE systems require a high up front investment and for some systems, energy sales are lower than expected; this combination can lead to operating losses or deferral accounts that are larger than anticipated.

Further, customers connecting to most new geoexchange, biomass, or wastewater DE systems should not expect lower bills than they would otherwise pay for heating and hot water from high efficiency equipment installed in a well-insulated building envelope. Geoexchange customers still need electricity to power heat pumps and as a supplementary heat source. Greenhouse gas (GHG) emission reduction forecasts can also be overestimated, as biomass and wastewater systems require natural gas backup, and some run exclusively on gas until load growth justifies a renewable source.

To set rates for DE systems, some municipalities use a cost-of-service methodology, while others simply peg rates to prevailing gas or electricity prices. Separating how much money a system needs to provide energy services (i.e. the revenue requirements) from the amount it collects from customers, may lead to significant shortfalls—or rates that are unjustifiably high—in future years. The interests of a municipality as both the utility owner and its regulator may not always align with the interests of its customers.

This paper concludes with a number of key findings and recommendations:

- The preferred regulatory approach is a cost-of-service regulatory model with a levelized rate structure to provide more affordable prices in early years, with a revenue deficiency deferral account to be repaid in later years as more customers connect;
- A deemed capital structure, target risk premium and, in early years, a disproportionately high fixed charge rate component, round out the preferred model;
- Up-front subsidies to offset capital costs can keep rates competitive and significantly enhance long-term financial viability.
- Particularly for mature, well-managed systems without exclusivity provisions, a "light handed" regulatory framework should be pursued, while still maintaining procedural fairness and decisions based on evidence.

1. INTRODUCTION

District energy (DE) systems generate heat at a centralized plant, or extract heat from other sources. This heat is then transferred to a fluid, and distributed via underground pipes to buildings where it is used for space and water heating, replacing conventional, on-site heating systems. The fluid is then returned to the source to be reheated and re-circulated. Some DE systems also provide space cooling in a similar way.

The development of DE systems is emerging as a strategy in reducing British Columbia's (BC) greenhouse gas (GHG) emissions, as DE systems may deliver the energy services needed for a lower carbon economy with greater efficiencies and lower emissions than individual furnaces, boilers, electric baseboards and water heaters fuelled by oil, natural gas, propane or electricity. Several of BC's sixteen "energy objectives" set out in the Clean Energy Act encourage DE, including promoting fuel switching, encouraging communities to reduce GHG emissions and use energy efficiently, and reducing waste by using waste heat, biogas, and biomass.

The advantages, barriers, environmental benefits, and technology choices of DE systems are generally well known[1]. Less understood is the economic regulatory framework that would encourage their development, recover capital and operating costs, provide owners with a profit, and offer customers rates and service levels comparable to or better than conventional alternatives.

Appendix 1 is a table describing BC's DE systems serving multiple customers. Appendix 2 shows the location, energy source, and ownership type of these systems, plus others serving universities.

2. STIMULATING DISTRICT ENERGY IN BC

Because of high up-front costs for long-lived assets, DE projects can be challenging to build without government support, including policy and regulatory initiatives and subsidies. Several approaches can help to stimulate the development of DE in BC.

Mandatory connection bylaws can compel buildings to connect, creating a monopoly in heating services.

The Clean Energy Act enables the Province to identify "prescribed undertakings," which are projects or programs to be carried out by public utilities for the purpose of reducing GHG emissions. The BC Utilities Commission (BCUC) must pass the costs of these undertakings on to the utility's ratepayers. DE systems are candidates for prescribed undertakings.

Provincial, federal, and utility programs offer subsidies and low interest loans; these are noted in the case studies that follow. For example, funding support from the Province's Innovative Clean Energy Fund was instrumental in establishing the Gibsons, University of Northern BC, and proposed Quesnel systems. The Canada-BC-Union of BC Municipalities Agreement on the Transfer of Federal Gas Tax Revenues (Gas Tax Agreement) delivers federal funding to local governments for projects contributing to reduced GHG emissions, cleaner water, or cleaner air. BC Hydro offered funding for DE prefeasibility and feasibility studies, and capital incentives based on expected electricity savings relative to a baseline scenario.

3. THE REGULATORY FRAMEWORK IN BC

Unlike most jurisdictions, the liberal definition of "public utility" in BC's Utilities Commission Act (the Act) means that most DE systems are regulated by the BCUC, unless the service is "provided" by a local government[2].

The BCUC's mission is to ensure that ratepayers receive safe, reliable, and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of those utilities are afforded an opportunity to earn a fair return on their invested capital. A Certificate of Public Convenience and Necessity (CPCN) constitutes the regulator's approval to construct a public utility system or addition.

A rate-setting process follows: for cost-of-service ("rate base") regimes, utilities prepare a revenue requirement application, which is the forecast revenue needed from rates in order to meet forecast expenses and a target return on equity (ROE). The revenue requirement is tested in a public process and adjusted by the regulator. A rate design may follow, which determines how rates should be structured among customer classes and consumption levels. The target ROE is set by adding a utility-specific risk premium to a benchmark rate of return based on long term Canada bond yields.

BCUC regulation of DE systems is evolving. Fortis BC Energy Inc. (Fortis) had intended to apply in 2011 for a regulatory framework for DE services within its Alternative Energy Services (AES) initiatives. Fortis argues that AES (notably DE, geoexchange, biomethane, and natural gas for vehicles) aligns the interests of the company and its customers with government policy, that most AES are regulated public utility services, and that DE rates should be set on a cost-of-service model. However, complaints by Fortis' competitors about possible cross-subsidization by its gas customers has prompted an Inquiry by the BCUC into Fortis' AES activities[3].

4. DISTRICT ENERGY SYSTEMS – BCUC-REGULATED

The services, financials, governance, and rate setting frameworks are examined for nine DE systems. In this section, four BCUC-regulated, privately owned DE systems are reviewed: a large, established steam utility, two biomass/natural gas systems serving new mixed use "green" developments, and a resort community where gas and electricity systems are BCUC-regulated but its individual mandatory geoexchange systems are not. In the next section, five DE utilities regulated by local governments are profiled, with the level of oversight ranging from thorough for Vancouver's Southeast False Creek system to cursory for the Westhills system in Langford. Space limitations preclude reviews of additional projects in Richmond, Surrey, North Vancouver, Revelstoke, Quesnel, and southeast Vancouver; however, their features are highlighted in Appendix 1.

4. 1 Central Heat Distribution Ltd. (CHDL) Steam System

CHDL is the oldest and largest DE system in BC. An investor owned utility, CDHL provides steam heat generated from natural gas to buildings in downtown Vancouver. CHDL was the first district energy company in Canada regulated on a cost-of-service basis by the provincial utility regulator. However, CHDL does not consider itself to be a natural monopoly and may consider applying for exemption from BCUC regulation in future.

CHDL was founded in 1968 to provide building owners with the opportunity to reduce heating bills and emissions. It sells about 1.2 million gigajoules (GJ)[4] of steam heat per year to over 3.25 million m^2 of floor space in 214 office, hotel, condominium, and institutional buildings via a 14 km network of high pressure pipes. While this volume makes CHDL BC's fifth largest utility, 1.2 million GJ represents only 0.3% of total energy volumes sold by BCUC-regulated utilities.

While energy use per customer is declining, many new buildings are connecting to the system. CHDL-served buildings do not need natural gas boilers, which tend to have "real world" efficiencies in the 60 to 70% range[5] as well as the staff, maintenance, and replacement costs associated with boiler operations. CHDL plant efficiencies are higher: boiler efficiencies are 87%, and steam sold represents 72% of fuel consumed[6].

BCUC's most recent review of CHDL rates and operations was in 2007, prompted by an application by CHDL to increase steam tariffs. In response to BCUC staff information requests, CHDL provided 122 pages of supplementary information. Despite two notifications, no CHDL customers intervened or participated in the subsequent negotiated settlement process: this suggests CHDL customers are satisfied, a conclusion reinforced by the absence of complaints filed with the BCUC. In addition to approving a lower than requested rate increase, BCUC:

- Required CHDL to undertake future energy efficiency projects as utility assets, with savings passed on to its customers, rather than shared with energy service companies;
- Temporarily reduced the ROE risk premium from 100 basis points to 50.

In arguing its case for a higher risk premium, CHDL claims it is subject to increasing risks and revenue instability. It notes the City's Southeast False Creek system and the potential system on the north side are financed by taxpayers and may therefore access grant programs available to municipalities. It also argues it is not a "natural monopoly" that is normally the basis for regulation, as it has no exclusivity provisions such as a mandatory connection requirement or franchise territory. The negotiated settlement leaves open an option for CHDL to apply "for exemption from regulation to be reviewed in a public hearing"[7]. Under s. 88(3) of the Act, the BCUC may limit or vary the application of the Act, but requires advance Cabinet approval to do so.

Unlike BC Hydro rates, CHDL rates are set in a four-step declining block rate structure: as steam consumption increases, the cost per 1,000 pounds per month goes down. This metered steam charge is based on the utility's costs, a portion of its gas costs, and Fortis gas transportation charges. In addition, a monthly variable fuel cost adjustment (essentially the gas commodity cost) reconciles actual costs with costs embedded in the steam tariff. The carbon tax, HST, and other taxes are then added.

While total GHG emissions would be higher without CHDL, natural gas consumed by CHDL still accounts for over 20% of downtown Vancouver's GHG emissions from space and water heating[8]. A review of alternative energy sources for the existing system and adjacent northeast False Creek has identified biomass as a promising resource to meet base loads, though uncertainties remain regarding biomass availability, price, trucking, storage, and emissions, as well as a potential plant location[9]. (The Seattle Steam Company has replaced one of its oil and gas boilers with a boiler burning clean urban

waste wood and land clearing debris.) If CHDL were to convert to a GHG-neutral fuel source, Vancouver's emissions would be reduced by 80,000 tonnes and would meet 12% of the City's 2020 emission reduction target[10].

4. 2 Corix SFU UniverCity Neighbourhood Utility Service (NUS)

Corix Multi-Utility Services Inc. (Corix) will own and operate a biomass energy utility to provide heat and hot water for the Simon Fraser University (SFU) campus and future units at the adjacent UniverCity residential development. Corix applied for and received a conditional CPCN for a temporary natural gas fuelled plant for UniverCity, but the BCUC suspended further consideration of the permanent biomass system pending more information. Funding from the provincial government's Public Sector Energy Conservation Agreement (PSECA) for an SFU/UniverCity biomass system should help Corix finalize the necessary details.

Consistent with the initial plans for SFU, in 1995 the City of Burnaby and SFU began planning a mixed-use, compact, and transit-oriented residential community. The SFU Community Trust provides sites to developers on a prepaid 99-year leasehold basis. UniverCity has about 3,000 residents in its first two phases, with heating provided by electric baseboards and hot water from natural gas. Burnaby requires developers in Phases Three and Four to comply with SFU Trust's green building requirements by installing thermal energy systems compatible with a DE system and prohibiting electric resistance heating.

Corix undertook a screening analysis of alternative energy sources for fuelling the NUS. Based on several financial and environmental criteria, biomass sourced primarily from construction and demolition sites emerged as the preferred resource. The NUS is central to the SFU Trust's comprehensive plan for UniverCity. In addition, the SFU campus natural gas boilers are responsible for about 85% of campus GHG emissions, and much of the University's total annual carbon offset costs of around $465,000. The NUS project cost estimate is $32.4 million, which would be offset by a $4.7 million PSECA grant if the SFU campus joins the project. A developer contribution of $1 per square foot of buildable area is expected to provide $2.223 million[11]. Additional funding of around $0.8 million is being sought from BC Hydro, and other potential funding agencies are being solicited. The NUS would reduce GHG emissions by 10,570 tonnes annually, about 58% the University's total emissions.

Corix' CPCN Application was reviewed by the BCUC through a written hearing process. There were no active interveners. Corix sought approval for a two phase project, a temporary natural gas boiler to serve initial residential loads, and a permanent biomass plant when justified by load growth. Approvals were sought for:

- A 60% fixed/40% variable (energy volume) rate design, with the relatively high fixed charge helping to mitigate uncertain energy consumption levels;
- Billing each strata based on building area and consumption metered at each building; individual units would be billed by the strata based on area;
- A 20 year levelized rate structure, with the variance between actual and forecast costs carried in a deferral account for future BCUC review; and
- An ROE with a 200 basis point risk premium, and a deemed capital structure of 40% equity/60% debt.

Corix forecasts UniverCity's energy demand at full build-out in 2020 to be 14,020 MW.h (50,500 GJ). Over 20 years, Corix forecasts a levelized rate of $160/MW.h, compared to $134/MW.h if the units were served by BC Hydro. The NUS rate also includes a franchise fee from UniverCity customers to SFU Trust at 3% of revenues. Corix notes the demand and price forecasts are highly uncertain, and the BCUC found them to be not credible enough to make decisions on biomass project size or rates.

In its Decision (C-7-11), the BCUC granted a CPCN for the temporary natural gas system only. It noted the PSECA grant could not be considered in its Decision as it followed the close of the evidentiary record, but expected the grant would help resolve uncertainties. With the notable exception of the risk premium, the BCUC accepted most of Corix' proposals, including:

- The 60% fixed/40% variable rate design;
- A 20 year levelized rate structure, but based solely on the temporary gas system, with a deferral account capturing the revenue requirement variances; and
- A deemed capital structure of 40% equity/60% debt, but with only a 50 basis point risk premium.

The BCUC has approved a gas-based residential tariff for the first phase, which also sets out customer and utility responsibilities. In 2012, customers pay a basic monthly rate of $0.5365/m^2 and a variable charge of $0.056/kW.h, consistent with the estimates in the CPCN Application.

Phase One went into service in the spring of 2012. Negotiations continue with SFU to connect the campus with the second phase biomass system, likely at a lower commercial rate given the higher load and load factor. Biomass technology has not yet been determined; a combined heat and power plant that would sell electricity to BC Hydro remains an option[12].

4. 3 Dockside Green Energy (DGE)

Dockside Green Energy LLP (DGE) is an investor-owned DE utility serving the Dockside Green development in Victoria. The CPCN approved a levelized rate structure and deferred depreciation as ways to achieve rates in the early years of utility operations that are competitive with conventional gas and electricity rates.

Dockside Green is being built on six hectares of former industrial land adjacent to downtown Victoria. The total planned development will comprise 130,000 m^2 of residential, office, retail, and light industrial space. It is designed, approved, and marketed with unprecedented commitments to sustainability. For example, Dockside Green must pay the City a penalty for any building area that does not achieve a "LEED Platinum" rating.

DGE is a utility established to provide space heating and hot water through joint partnership of VanCity Capital Corp., Terasen Energy Services Inc. (now Fortis), and Corix. The system consists of a central heating plant with a wood residue gasification system, back-up natural gas boilers, and distribution pipes to deliver hot water to metered heat exchangers. Bulk bills are issued to several strata corporations; each strata sub-meters energy use to allocate costs to residents and tenants. Corix has been contracted by DGE

to provide operation, maintenance, and customer service. The system cost was $6.114 million, for which the federal "Technology Early Action Measures" (TEAM) program provided $1.5 million, a subsidy of 25%.

DGE initially considered entering into a partnership with the City to avoid BCUC regulation, but was advised that partial municipal ownership would still subject the system to BCUC jurisdiction. DGE applied for a CPCN in December 2007. The Application contained proposals to minimize risks and try to keep rates competitive:

- Extending the system to serve off-site buildings, particularly a large hotel;
- A fixed price turnkey contract for the Nexterra system;
- A 50% fixed/50% variable rate design;
- A 20 year levelized rate structure, to provide a reasonable rate in the early years, and a deemed capital structure of 60% debt and 40% equity;
- A fixed price, long term biomass contract;
- If operating cash flows are less than the principal and interest payments on the utility's debt, the developer makes up the shortfall by way of non interest bearing contributions repayable over six years beginning in year 15; and
- Deferral of depreciation for the first seven years, and depreciation over 50 years starting in year eight.

In its Reasons for Decision (C-1-08) the BCUC generally approved the CPCN Application, including the capital structure and risk premium of 100 basis points. However, the BCUC initially rejected DGE's proposal that the utility be allowed to recover in customer rates any capital, operating, maintenance, biomass, and natural gas costs that are higher than the estimates included in the application. In other words, the BCUC considered the technology and biomass risks to be risks borne by the shareholder, so any overruns were not to be passed on to ratepayers. DGE was successful in its appeal to have these conditions removed from the original CPCN. In its Reconsideration Decision, the BCUC concluded it would review the circumstances before judging whether cost overruns are prudently incurred and included in higher rates.

The approved rate for 2011 is $0.24/m^2/month (fixed) plus $14.07/GJ (variable), escalating at 3% per year through 2018. The annual bill for a 100m^2 condominium is around $600 per year.

DGE has experienced several challenges in its first few years of operation. Soft market conditions slowed construction, resulting in lower than forecast loads and revenues. The original provider of biomass failed to deliver. DGE continues to seek alternative supply sources, with moisture content, foreign objects, and contaminants (e.g. nails, glue) providing challenges. With a much smaller load factor, running the biomass plant was not practical, and the plant has been using the natural gas boilers to supply customers. (At 60-65%, gas conversion efficiencies are low: in 2010 DGE bought 9,828 GJ of gas and sold 5,997 GJ of energy.) A contract with the Delta Hotel will provide the new load needed to run the biomass system, once a reliable biomass source is found.

These start up challenges are reflected in DGE's income statements[13]:

Year	Revenues	Expenses	Operating Shortfall	Retained Earnings
2008	$ 43,243	$ 233,972	$ 190,729	($ 190,729)
2009	$ 150,390	$ 605,364	$ 454,974	($ 645,702)
2010	$ 162,118	$ 475,969	$ 313,780	($ 959,483)

4.4 Corix Sun Rivers Resort Community

Sun Rivers is located on 186 hectares of Tk'emlups (Kamloops) Indian Reserve lands. With the exception of the village centre, low residential densities do not support a central DE system; rather, each house or building has its own ground source heat pump owned by Corix. Residents are billed a monthly geothermal fee, which is not regulated by the BCUC, as well as for electricity and natural gas provided by Corix, which are BCUC-regulated.

At full build-out, Sun Rivers is designed to accommodate 5,500 residents in 2,000 dwellings, most of which will be detached houses. Marketed as a golf-oriented, adult-oriented, master-planned community, about 600 units are occupied as of mid-2011. All dwellings have heat recovery ventilators and geothermal heating and cooling, and many are built to "Built Green Platinum" levels, with Energuide ratings in the mid to high 80s. At completion, geothermal systems are expected to reduce GHG emissions by 8,000 tonnes per year when compared to conventional natural gas heating.

Corix funds and installs each building's vertical ground loop at a cost typically in the $15,000 to $20,000 range. The indoor geoexchange equipment and hot water tank are owned by the homeowner. Residents are billed a one-time connection fee and a monthly "ground loop access fee," averaging about $68/month and ranging between $30 and $175/month depending on equipment size, as part of their monthly Corix utility bill that includes potable water, irrigation water, natural gas, and electricity charges.

Sun Rivers Development Corporation received CPCNs for gas and electricity utility franchises in 1999. While the electricity CPCN notes Sun Rivers' intent to install heat pumps, Sun Rivers held the view that the geothermal facilities are equipment being rented to the homeowner, rather than energy services that would make it a geothermal public utility.

Corix purchased the energy infrastructure in 2002. Its regulated utilities operate as resellers of electricity and gas they buy from BC Hydro and Fortis. Its customers pay the same rates as BC Hydro and Fortis for the same customer class. Depending on its distribution costs, Corix can earn a profit margin from buying the energy at lower commercial rates and reselling at higher, primarily residential rates.

Two other features of Sun Rivers' unique energy picture are worth noting: the high electricity consumption per household and the financial performance of both regulated utilities. At 15,300 kW.h (55 GJ) per residential customer per year, Sun Rivers residents consume 50% more electricity than the average BC Hydro customer[14]. This is surprising, given the energy efficiency of the housing stock. It appears the Sun Rivers' geoexchange units may not enjoy a cost advantage over high efficiency gas furnaces and central air conditioning when the electricity to power the heat exchanger is included. The average

Sun Rivers household pays $1,600 per year for 55 GJ of electricity and 12 GJ of gas, plus another $800 in geothermal access fees.

Corix is experiencing operating shortfalls on both its Sun Rivers regulated utilities:

	Natural Gas Utility	Electric Utility
2010 Revenues	$ 140,654	$ 791,477
2010 Expenses	$ 148,768	$ 1,077,911
2010 Operating Shortfall	$ 8,114	$ 286,434
Retained Earnings, Yr. End 2010	($ 131,751)	($ 702,608)

As with any BCUC-regulated utility, Corix is generally entitled to charge its customers rates sufficient to enable it to earn a return on its invested capital. However, it has never filed a revenue requirement application to raise rates above the comparable BC Hydro or Fortis rates. Corix has no plans to apply for rate increases or restructure its utilities to a cost-of-service model, given favourable revenue and cost projections as the development moves to full build-out. Although the geothermal fee is not regulated, Corix states that each of its Sun Rivers services is managed on a stand-alone basis and there are no cross subsidies between regulated and non-regulated activities[15].

5. DISTRICT ENERGY SYSTEMS – LOCAL GOVERNMENT REGULATED

5. 1 City of Vancouver Southeast False Creek Neighbourhood Energy Utility (NEU)

Vancouver's NEU provides space heating and hot water to all buildings in Southeast False Creek, including the former Olympic Village. It is the first system in North America to use heat recovered from untreated wastewater. Sewage heat recovery supplies about 70% of the annual energy demand; natural gas boilers provide backup and winter peaking, and at times (including the summer of 2010) when energy demand is too low for wastewater system operation.

The NEU is owned and operated by the City of Vancouver and managed by the City's Engineering Department. Its goal is to minimize GHG emissions via a financially self-sustaining, commercially operated utility delivering competitively priced energy services.

The Province amended the Vancouver Charter in 2007 to enable the City to provide energy utility services. This was followed by the Energy Utility System Bylaw, making connection to the NEU mandatory for all new buildings within the Official Development Plan area, which at build-out is expected to contain about 557,000 m^2 of floor space. The City also requires rezoning applicants for sites over two acres to investigate the viability of a DE system.

The NEU exhibits several features that warrant consideration by other systems:

- A design that engages pedestrians and drivers with the False Creek Energy Centre, including portals, windows, and decorative stacks;
- A set of ownership, governance, and rate setting principles, including periodic reviews on the merits of continued City ownership;
- An independent Expert Rate Review Panel to advise staff and City Council on proposed rate increases.

NEU system total capital costs were $32,003,000[16], of which $9,876,000 (31%) was a grant through the Gas Tax Agreement. GHG emissions are expected to be reduced by 7,600 tonnes per year, or 64% less than a typical energy supply mix of electric baseboard heat for residential units and natural gas for ventilation air, hot water, and non-residential space heating.

As with Dockside Green and UniverCity, NEU rates are comprised of a fixed capacity charge related to NEU's fixed costs, and a metered variable energy charge. Individual stratas are responsible for apportioning costs among individual unit owners: some buildings have sub-meters and bill on measured consumption; others apportion charges based on floor area. Rates are designed to be competitive with BC Hydro rates, so are levelized to under-recover full costs in early years. Rates then rise to recover all costs over a 25-year time horizon. Initial operating cash shortfalls are financed through a rate stabilization reserve, which serves as a line of credit. Once the NEU begins to generate an operating surplus, anticipated around 2020, the full amount of the surplus will repay the reserve's principal and interest. A target 10% return ($800,000 to $1 million per year) on a deemed 40 % equity component is included in the 25 year projected operating budget.

NEU's 2010 rates were set at BC Hydro's 2010 rates, plus 10%. Rates were increased by 3.15% for 2011 and 3.22% for 2012: for a residential unit, this is a 2012 capacity levy of $0.469/m^2/month plus an energy charge of $39.395/MW.h ($10.94/GJ). Annual increases that include an escalator will be critical to the financial sustainability of the NEU: for 2012, the rate escalation factor of 1.22 percentage points above 2.0% core inflation will help maintain the levelized rate structure.

5. 2 Prince George Downtown Biomass System

The City of Prince George is investing $14.14 million to build the largest biomass-based system in Canada. Construction began in mid 2011 for a spring 2012 in-service date. The system will reduce GHG emissions by about 1,868 tonnes per year by replacing natural gas space heating and hot water in eleven downtown buildings. Favourable economics are due to the City's success in obtaining grants for over 70% of the capital cost.

The City identifies a downtown district energy system (DDES) as the priority initiative under its Energy and Greenhouse Gas Management Plan. An initial proposal for a free standing plant close to residential areas was opposed because of community concerns over particulate emissions. The revised project improves the existing biomass incineration system at the Lakeland sawmill, just north of downtown.

Lakeland Energy Supply Agreement Bylaw 8276 authorizes the City to enter into a contract with Lakeland, whereby:

- Lakeland supplies 15,000 tonnes of sawmill residue per year for incineration in a new plant and energy transfer station (ETS) near the sawmill;
- Particulate reduction credits belong to Lakeland and GHG reduction credits belong to the City; and
- Lakeland sells the thermal energy to the City at a fixed price with escalator for ten years; the renewal term energy price will be pegged to the market value of biomass in year nine.

The bylaw was approved after a counter-petition process in mid 2010 gave the electorate the opportunity to oppose it. Federal funding triggered a review under the Canadian Environmental Assessment Act, and approval was received in late 2010. Construction of a natural gas peaking and backup plant, the ETS, and distribution system began in August 2011. The $2.75 million peaking plant also includes rentable commercial space.

The City has obtained $10.159 million in senior government grants:

Municipal Rural Infrastructure Fund Grant	$ 5,332,000
Green Municipal Fund Grant	$ 461,000
Gas Tax Agreement Grant	$ 4,366,000
Pre design and feasibility soft costs	$ 295,000
Loan from FCM Green Municipal Fund (GMF)	$ 3,687,000
Total Project Cost	$ 14,141,000

The City is both the owner of the DDES and its major customer, as owner of seven of the eleven connected buildings and contributing about 52% of the revenues. The City's financial models anticipate a rate structure for energy based on 80% of the cost of natural gas ($45/MW.h or $12.50/GJ) plus a negotiated capacity charge based on the avoided natural gas boiler capital, maintenance and insurance costs in the customer's building. The capacity-to-energy charge ratio in early years is 33:67. The utility will install, own, and maintain the heat exchange equipment in the eleven buildings. Simply put, in 2012 the City expected to buy 11,561 MW.h (41,600 GJ) of energy from Lakeland at $22.50/MW.h ($6.24/GJ) and sell it for an average of $75.87/MW.h ($21.10/GJ)[17]. Customer contracts have a fixed escalator for the first ten years.

Financial projections underscore the importance of grants in providing the City with the opportunity for a new revenue source. Annual cash flows were expected to be positive from the first full year of operation, providing net revenues averaging $156,000 per year until the GMF loan is repaid in 2022, rising to an average of $460,000 per year thereafter.

Decisions on ownership structure (e.g. a municipally owned corporation with a separate Board, or a utility functioning within City administration) and associated rate setting processes and responsibilities have yet to be made[18].

In April 2012, the sawmill was destroyed in an explosion and fire. While the adjacent plant/ETS was not damaged, the residue supply has been lost.

5. 3 Whistler Cheakamus Crossing District Energy System

The Cheakamus Crossing DE system is owned and operated as a municipal service on a cost recovery, non-profit basis by the Resort Municipality of Whistler (RMOW). Rates are set per unit area served; there is no energy charge.

Cheakamus Crossing—also known as Athlete's Village—was guided by a Comprehensive Sustainability Plan with a commitment to compact, sustainable neighbourhood planning and design. The system extracts heat from treated wastewater effluent, supplemented in cold weather by natural gas boilers. The energy is transferred by heat exchangers to a fluid piped into buildings, where it is upgraded by heat pumps to provide up to 95% of

space heating, hot water, and cooling needs. In-home electric heating supplements the heat pumps for the remainder. The DE system cost of $4.1 million was absorbed into the $144 million total building costs, which were shared among the Province (land and land remediation), the Vancouver Olympic Committee (VANOC) ($35 million), RMOW ($8 million) and the Municipal Finance Authority (MFA) ($100 million loan). RMOW has received a two year extension from the MFA to repay a $13 million outstanding balance.

The system was developed by the Whistler 2020 Development Corporation and the RMOW Environmental Services Department, and is operated by RMOW's wastewater treatment staff. The in-home equipment is owned by the homeowner, and warranted for the first two years of occupancy. The system is expected to reduce GHG emissions by up to 1,600 tonnes per year when compared to conventional gas furnaces. The system is designed to serve 2,000 to 2,200 residents, occupying 85,000 m^2 of floor space in about 600 dwellings. The 2010 billable floor area is 42,600 m^2 in about 300 units.

The capital cost has been paid, so RMOW is not including any capital cost recovery or return on invested capital in its revenue requirements. Rates are set annually by Council based on staff reviews of operating costs. The amount to be received from ratepayers in 2011 was $195,000, consisting of:

- $125,000 in operating costs (including $40,000 for electricity and $50,000 for natural gas); and
- $70,000 to a replacement reserve fund (to provide half of the capital replacement costs).

Therefore, Bylaw 1951 sets a unit rate of $4.58/$m^2$ per year to recover $195,000 from owners of 42,600 m^2 of floor area. As Phase One build-out advances, the unit area charge is expected to decrease.

RMOW staff estimate that the cost to homeowners would be about 84% of the costs from electric baseboard and hot water heating ($9.60/$m^2$ per year compared to $8.06/$m^2$ per year, which includes $3.48/$m^2$ per year to power the heat pump, in addition to the $4.58 unit area rate). However, the $70,000 replacement reserve allocation assumes the remaining 50% to pay for future replacement will come from senior governments. This may prove to be optimistic: while provincial and federal governments often co-fund water and sewer infrastructure, they are less inclined to subsidize energy utility upgrades.

Some residents have publicly expressed dissatisfaction with the cost and effectiveness of the system[19]. In the longer term, additional variables will influence the cost comparison outcome:

- Costs (if significant) to fix technical problems (instrumentation, corrosion, leaks);
- BC Hydro's future rate increases; and
- In cold weather, the tradeoff between the utility's use of natural gas to supplement the effluent-sourced heat vs. the customers supplementing their heat pump output with electric second-stage heating.[20]

5. 4 Upper Gibsons Geoexchange District Energy Utility

The Town of Gibsons owns and operates a geoexchange system, the first municipally-owned utility of its kind in North America. The utility is expected to generate revenue for the Town, which is seeking to reduce reliance on property taxation. GHG emission reductions are estimated at 335 tonnes at Phase One build-out of just over 100 dwelling units, assuming natural gas as the alternative.

The DE system consists of horizontal "slinky" geoexchange loops beneath a park, and a pumphouse to circulate an ethanol/water mix through distribution pipes. The existing field serves the first 27 lots and the pumphouse was sized for the full build-out of 116 lots. The Town installed and owns the geoexchange field and pumphouse; the developer (Parkland) was responsible for installing the distribution pipes which are owned by the Town to property lines. The homeowner owns the pipes beneath the yard and in-house heat pump.

The $1.4 million system had five funding sources, with three senior government programs contributing 60% of the cost:

- $244,080 from the Province's Island Coastal Economic Trust
- $325,115 from the Province's Innovative Clean Energy Fund
- $256,000 from the Gas Tax Agreement
- $190,000 from the Town
- An estimated $385,000 from the developer for the distribution system

Gibsons District Energy Utility Bylaw 1128 sets the rates and areas subject to a mandatory connection. Rates are designed to undercut natural gas rates by 10%, and are based on a heat loss calculation for each dwelling provided with the Building Permit Application. Consumption is not metered. Rather, there is a basic charge of $34.50 quarterly, and a quarterly charge of $22.32 per KW of peak heating capacity, which is the required capacity of heating appliances for the house as set out in the 2006 BC Building Code. This translates to an annual bill of about $500 for a 140m^2 home, or $3.57/m^2.

As of late 2011, only five houses in the 27 lot first phase have been completed. Business-case financial projections assumed a more rapid build-out. While the Town's vision is to service a much larger area with geothermal, feasibility analyses have not been undertaken.

5. 5 Westhills Langford District Energy Sharing System (DESS)

Langford is a rapidly growing city of 29,000, one of Greater Victoria's "West Shore" communities. The 209 ha Westhills site is being developed in phases by the Westhills Land Corp. (WLC), consistent with the principles of the Capital Regional District's Regional Growth Strategy and the Westhills Green Community Master Plan.

This Master Plan was prepared through a design charette process, guided by LEED Neighbourhood Development principles and supporting a DE utility. At full build-out, Westhills will have between 3,000 and 6,000 residential units, plus commercial, civic, and educational facilities. All single family dwellings are to be "Built Green" certified, most are on small lots and many have legal secondary suites or rear yard carriage houses. Sustainability and energy efficiency figure prominently in Westhills' marketing.

Sustainable Services Ltd. (SSL) is a utility affiliate of WLC, providing thermal heating, cooling, and water delivery. The DESS uses a ground source geoexchange system: the first phase, serving about 200 homes, consists of a borefield beneath a community sports field, a pumphouse, and a metered distribution system for the water/glycol fluid. Cost was about $3 million, or about $15,000 per home, with the energy savings expected to pay back the added capital costs in 10 to 15 years[21]. No government subsidies were sought. Phase Two is sourcing waste heat from an ice arena refrigeration plant, and a future phase may tap into Langford Lake as the energy source.

SSL's energy customers are provided with a water source heat pump for space heating and cooling, and hot water preheating: unlike Sun Rivers, Gibsons and Whistler, the utility owns and maintains the equipment within the dwelling. An auxiliary electric heater augments the heat pump in cold weather or when the thermostat is raised by more than one degree. BCUC regulation is seemingly avoided by having the municipality assert jurisdiction through the City of Langford's Multi-Utility Bylaw 1291. This 62 page bylaw:

- Establishes the City of Langford Multi-Utility, including Water and Energy Services, as a municipal service;
- States that the City may provide the Services directly, or through a Service Provider, "including, without limitation, SSL";
- Specifies Westhills as the area in which the Services may be provided; and
- Sets the terms, conditions, rates, fees, and charges for Water and Energy Services.

Rates for 2011 were identical to BC Hydro's 2010/11 residential inclining block rate structure, but without BC Hydro's rate rider. "After 2010, the Service Provider may increase the rates in each year by up to 10% above the preceding year's rate. If in any year the permitted increase is not applied by the Service Provider, the percentage remaining may be added in the subsequent year[22]." There is apparently a confidential agreement between the City and SSL that best efforts will be made to continue to peg the DESS rates to BC Hydro's future rates[23]. The provision for a 10% rate increase—a doubling every eight years—calls into question the bylaw's assertion that rates are based on costs of providing, maintaining, and expanding the Energy Services.

6. RATE COMPARISONS

Table 1 estimates the cost per megawatt hour paid by residential customers of seven DE systems for heat and hot water in 2011, plus comparable costs for BC Hydro electric heating and Fortis gas customers. Table 2 compares fixed charges and energy charges for six utilities that use an area-based approach.

Estimates are based on a consistent set of assumptions, and derived from tariffs, sales and revenue reports or projections, and utility website information. Estimates exclude the cost of electricity to operate or supplement a DE customer's heat exchangers. Gas furnace and hot water tank inefficiencies are not accounted for: therefore the "effective" cost for Fortis customers will normally be higher.

Table 1: Rate Comparisons[24]

Utility	Estimated Cost per MW.h (2011)
Fortis Lower Mainland Gas	$ 40
Fortis Vancouver Island Gas	$ 60
Fortis Whistler Gas	$ 60
Prince George Downtown DE	$ 76 (2012)
Lonsdale Energy DE	$ 68
Central Heat DE	$ 50
Southeast False Creek DE	$ 84
BC Hydro (heat)	$ 86
Westhills DE	$ 84
Fortis BC Revelstoke Propane	$ 92
Dockside Green DE	$ 98
Corix UniverCity DE	$ 145 (2012)

Table 2: Area-based Residential Rate Comparisons

Utility	Fixed Charge $/m2/yr	Variable Rate $/MW.h	Notes
Corix UniverCity (2012)	$ 6.44	$ 56	Fixed charge stable to 2031; variable rises about 1%/yr
Dockside Green (2011)	$ 2.88	$ 50.70	3%/yr escalation to 2018
Southeast False Creek (2011)	$ 5.45	$ 38.17	Expect CPI + at least 1.15%/yr escalation
Prince George Biomass (2012)	Depends on building	$ 45	
Whistler Cheakamus (2011)	$ 4.58	none	Excludes cost to run heat pump (est. $3.48/m2/yr)
Upper Gibsons	$ 3.57	none	Excludes cost to run heat pump

Of course, rates are not the same as bills, with bills being influenced by a host of factors, including the energy efficiency of the equipment and the building, occupant behaviour, and weather. But the tables indicate that the costs to the customer of DE systems, particularly newer ones, may be higher than conventional systems. Of the three least-cost DE systems, Prince George is heavily subsidized, and CHDL and Lonsdale are mature systems benefiting from low natural gas prices and high energy densities (i.e. high MW.h consumption per hectare).

From the customer perspective, a DE cost premium may be justified by potential benefits, including:

- Less exposure to fluctuating gas and rising electricity prices;
- Lower initial and lifecycle costs of DE-provided in home equipment;
- The DE utility may be responsible for maintenance;
- Geothermal and hydronic heating may be more comfortable than drafty forced air or baseboard electric;
- Floor space may be freed up due to a smaller equipment footprint; and
- The use of renewable fuels, ground source, or waste heat reduces GHGs and other environmental impacts, and may improve the environmental performance of natural gas.

However, prospective DE customers may wish to weigh benefits against possible drawbacks, such as lack of choice, higher rates due to unanticipated but prudently incurred costs or cost overruns, and inadequate regulatory oversight. Possible ways policy makers and regulators can mitigate these and other concerns are discussed in the concluding section.

7. CONCLUSIONS AND RECOMMENDATIONS

The preceding project summaries show there are economically viable opportunities for the large scale deployment of DE systems using renewable technologies, especially in high density, mixed use urban areas, and when government subsidies, low interest loans, and other sources of patient capital can be procured. This section summarizes findings and policy recommendations for governments on how DE systems can best be regulated to encourage their development, offer fair rates, and provide owners with an opportunity to earn a return.

7.1 Customer value should be central to DE systems.

To justify the development of DE systems solely on the basis of narrowly focused "lower carbon emissions" is insufficient, particularly in BC with its low carbon electricity. Nor will potential costs savings be an adequate rationale for switching to DE systems; depending on a customer's circumstances, individual high efficiency heating systems (especially air or ground source heat pumps) and energy efficiency investments can provide comparable energy services and GHG reductions at similar costs to DE.

The value of a DE system to both individual customers and the community must therefore be emphasized. A DE system should complement other components of community sustainability, supporting compact, mixed use development, water and waste management, air quality, and GHG emission reduction. DE customers must also realize direct benefits from a DE system, including safe, reliable, and competitively priced energy services.

7.2 An arms length, cost-of-service regulatory regime benefits both customers and owners.

High up-front costs discourage many long-lived energy investments--including DE investments--that are weighted to capital costs rather than energy commodity costs. Under a cost-of-service regulatory framework, a DE system can be confident of a revenue stream over the life of the investment. While comparisons with gas or electricity rates are helpful, pegging DE rates to a percentage of BC Hydro or Fortis rates may pose long-term risks to the utility.

Local government ownership or oversight of a DE system is often cited as an advantage because it avoids regulation by the BCUC. Yet, a system with an independent regulator also benefits DE customers, with its standards of procedural fairness and evidence-based decisions. Systems regulated by political bodies do not offer the same level of customer protection, particularly when the regulator is also the system owner and has mandated a monopoly, or where the political body may not be adequately fulfilling its fiduciary responsibilities. (Unlike a water or sewer customer where almost all users are voting taxpayers, the small customer base of a municipal system wields minimal influence.)

Municipalities should consider appointing independent experts to review their DE revenue requirements and rate proposals, as Vancouver did. The BCUC itself may be able to provide advice. Public hearings, meetings, or facilitated negotiated settlement processes enable the utility and its customers to review proposals and concerns.

7.3 There are benefits to both public and private ownership, and related financing models.

Municipal DE systems can be owned and/or operated by the local government through an existing department, a utility subsidiary, a contract with a private utility or an equity partnership with a private utility. Public ownership may involve greater access

to grants, cheaper debt financing, and income tax, property tax, and franchise fee exemptions. On the other hand, some investor-owned DE systems receive property tax exemptions through "green energy" bylaws. Investor owned utilities may also have access to favourable tax instruments, such as accelerated capital cost allowances. Creative public–private co-funding and co-ownership arrangements, perhaps involving leasing, may combine the benefits of public ownership with private utility risk tolerance, access to capital, management, and operational expertise.

7.4 Local government leadership is often instrumental in DE system development.

Policy and regulatory support by local governments is significant in implementing most DE systems, whether or not the municipality has an ownership stake. Tools include DE goals and policies in community and neighbourhood plans, DE governance principles, feasibility studies, and mandatory connection bylaws. However, local governments should be mindful to temper their enthusiasm for direct climate action with the recognition that DE proposals come with a package of project development, operating, and economic risks. Many BC urban areas lack the energy demand densities (MW.h/ha) needed to justify a DE system.

7.5 DE programs should be included in Power Smart program reviews.

BC Hydro has ended subsidy programs for DE feasibility studies and capital cost contributions. However, as BC Hydro increases its electricity savings targets in responding to Clean Energy Act objectives, Power Smart may consider other ways to support DE systems in the future.

Both the BCUC and the Province's BC Hydro Review Panel[25] urge BC Hydro to re-evaluate its electricity conservation programs to ensure value for money, while decreasing overall costs to ratepayers. BC Hydro's estimated program cost per unit of electricity saved by moving space heating and hot water customers to a future DE system is one criterion. There are also more subjective societal considerations, including the likelihood that customers of a BC Hydro-assisted DE system will be paying more for heat and hot water, and emitting more GHGs, than they would if they remained BC Hydro customers for these energy services.

7.6 Senior governments should investigate a public-private equity fund with municipal organizations.

With the "prescribed undertakings" section of the Clean Energy Act and amendments to the Demand Side Measures Regulation, the Province may be looking to utility ratepayers to support efficiency and alternative energy initiatives for the purpose of reducing GHG emissions. While analyses of GHG emission reduction economics of DE systems and the monetization of their environmental attributes are beyond the scope of this report, a cursory review of Appendix 1 suggests the GHG reductions tend to be modest and the government subsidies per tonne reduced are very high.

The Province may wish to examine other policy and taxation instruments to support DE. For example, the reversion to the PST/GST tax regime provides an opportunity to revisit tax policy on renewable energy equipment. Senior governments should consider approaches used in Europe, where DE systems are typically financed through a government subsidy of around 30%, which may be reimbursed after commissioning. Counting the 30% subsidy as equity makes it easier for banks to finance much of the balance[26]. Consistent with this approach, the Federation of Canadian Municipalities is

proposing public-private equity fund, established by the Federal Government to leverage private capital for investing in municipal DE systems and other renewable energy projects. A portion of debt financing would still be required from the municipality.

In BC, the government should be mindful of the foregone revenues and resource rents (e.g. water rentals, natural gas royalties, carbon taxes) that would accompany a significant shift from conventional utilities to renewable DE systems.

7.7 DE system rate structures should encourage efficiency.

Most utility rate structures have shifted from declining block rates – whereby unit prices decrease as consumption goes up -- to a flat or inclining block structure. For example, BC Hydro's inclining rate structures discourage consumption because the price per kW.h goes up as consumption increases, thereby incenting customers to invest in energy efficiency. Conversely, the DE case studies indicate four ways that make it harder for their customers to justify energy savings actions:

- CHDL steam rates are set in four declining blocks;
- Gibsons and Whistler systems are not metered;
- Individual suites in many stratas are not sub-metered, so bills are allocated on a square footage basis; and
- A large percentage of revenue requirements for UniverCity, Dockside Green, and NEU are collected through a capacity levy, independent of energy use.

There are reasons for these approaches to rate design. In start-up years, a higher capacity charge reduces financial risk, particularly when energy consumption forecasts fail to materialize because customers' units are built to LEED or high Energuide standards. (This also means owners "pay twice", through the higher construction cost of efficiency investments and the high capacity charge.) And since most DE energy is sourced from no or low cost, non-carbon, and renewable resources, discouraging its consumption may not be a societal priority. Nonetheless, as DE systems mature, regulators should consider sending more transparent price signals by shifting revenue requirements more towards energy consumption. Building officials should also consider mandatory metering and sub-metering in codes, covenants, or development agreements.

7.8 The BCUC should review regulatory policies and procedures for small utilities.

Over time, the challenge for the independent regulator will be to provide effective yet streamlined regulation for a large number of small DE utilities. The "large utility" model applying to Fortis and BC Hydro, often involving integrated resource plans, formal and adversarial oral public hearings, thousands of pages of evidence and answers to questions, and intervener funding paid by the utility, will not work for small utilities. Yet the interests of utility ratepayers captive to a DE system would suggest a high degree of oversight, as opposed to other energy services (e.g. solar thermal, NGV, biomethane) that are open to competition.

Ideas to resolve these matters should be forthcoming from the BCUC's findings from its AES Inquiry. As noted earlier, there are exemption provisions in the Act that CHDL and others may be interested in pursuing. A light handed regulatory framework that does not subject small DE systems to exacting BCUC regulation may evolve, once a DE utility proves to be well operated and managed, with satisfied customers.

GLOSSARY

Capital Structure/Deemed Capital Structure The manner in which an entity is financed, usually including debt and equity. A deemed capital structure used for rate-making purposes differs from a company's actual capital structure: a regulator may deem a capital structure for a utility when it considers the actual capital structure is inappropriate.

Cost of Equity In regulatory proceedings, the cost of equity is generally determined in relation to what could be earned on investments of similar risk in the unregulated sector. It is often determined as the sum of the yield on a debt security (usually the yield on government or corporate bonds) plus an estimate of the equity risk premium (i.e. the required return on the utility's equity over the required return on the debt security). The BC Utilities Commission sets a target or allowed rate of return on equity for each utility based on Government of Canada bond yields plus a risk premium that reflects the perceived risk associated with that utility.

Cost of Service The total cost of providing the energy service, including operating and maintenance expenses, depreciation, amortization, taxes, and cost of capital. The cost of service is also known as revenue requirements.

Deferral Account An account that records the deferral of a cost or revenue until a future date for recovery from or refund to a utility's customers. They are used by utilities and regulators to keep rates stable and protect customers from volatile fluctuations in rates from year to year. The deferral accounts usually serve to defer variances between forecast and actual costs or revenues, to match costs and benefits for different generations of customers, and to smooth out the rate impact of large non-recurring revenues or costs. Deferral accounts are also known as regulatory accounts. Deferred asset accounts are usually recovered by a "rate rider" appearing as a separate line item on a utility bill.

Fixed Charge See "Rate Design"

Levelized Rates The levelized rate represents the per unit price at which energy is provided from a specific system over its lifetime in order to break even. A levelized rate structure reduces the rates for early customers by under-recovering costs of service during the early years of operation, capturing these amounts in a revenue deficiency deferral account, and recovering the value of the account over a predefined term (often 20-40 years). In this way, the high "front end" costs to develop the system are recovered from all customers.

Rate Design The method for apportioning the revenue requirement among the various utility services and customer classes. For residential and small commercial customers, the most common rate design is a basic or fixed charge (recovering most of the fixed costs of the system, regardless of whether any energy has been used or heat consumed) and a variable "per unit" energy charge (recovering fuel costs and variable operating costs). Many district energy utilities consider that connected floor area is an appropriate and convenient measure of the fixed costs incurred to provide district heating service.

Rate of Return the percentage return a regulated entity is allowed the opportunity to earn. It provides an amount equal to the cost of financing the investment required for regulated operations. The financing costs include both the cost of debt (usually the utility's actual cost associated with debt financing, including interest payments) and the cost of equity capital (see "Cost of Equity")

Return on Equity The percentage return allowed for the invested equity of utility shareholders.

Risk Premium See "Cost of Equity"

APPENDIX 1: DISTRICT ENERGY SYSTEMS IN BRITISH COLUMBIA

District Energy Systems in British Columbia: Profiled in Report										
System	Energy Source & Services	Regu-lator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/yr)	Energy Sales (year)	Connected Floor Space or Custom-ers, 2011	Connected Floor Space or Custom-ers, Full Build-out	Ownership/ Governance	Rate Setting Principles
Central Heat Distribu-tion Ltd.	Natural Gas with oil back up, raising steam for heat, hot water and cooling, Vancouver, CBD	BCUC	n/a	none	none (emits 80,000 tonnes/yr)	1,200,000 GJ (2010)	3,250,000 m^2	n/a	Investor owned, not publicly traded; no exclusivity provisions	Steam tariff based on cost of services, including gas cost variance pass through; declining block rate; 50 bp risk premium till 2019
CORIX SFU UniverCity	Heat & hot water from natural gas (phase 1) and biomass (phase 2) with gas back up; possible CHP	BCUC	$32.4 million	$4.7 mil-lion (min.) (15%)	10,570 (assumes biomass; SFU campus only)	50,500 GJ (2020)	under construc-tion	206,572 m^2 (2019; UniverCity only)	Investor owned; agreement with SFU Trust, 3% Franchise Fee payable to SFU Trust; mandatory connection by law	50bp risk premium; on 40% deemed equity; 60/40 fixed/variable rate structure variable escalating at 1%/year; levelized over 20 years with deferral account
Dockside Green Energy	Heat & hot water from wood gasifica-tion (expected 2011); natural gas back up system used 2008-2011	BCUC	$6.114 million	$1.5 million (25%)	n/a (goal to be GHG neutral re onsite energy use)	5,997 GJ (2010)	5 strata customers	130,000 m^2 on 6 ha	Joint partnership (VanCity and two utilities); contract with Corix to operate system, mandatory connection bylaw	100 bp risk premium on 40% deemed equity; 50/50 fixed/variable rate structure escalating at 3% /year; levelized over 20 years with deferral account; deferred depreciation

System	Energy Source & Services	Regu-lator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/ yr)	Energy Sales (year)	Connected Floor Space or Custom-ers, 2011	Connected Floor Space or Custom-ers, Full Build-out	Ownership/ Governance	Rate Setting Principles
CORIX Sun Rivers Geother-mal	Individual ground source (geother-mal) heat pumps; gas and electricity utilities	geo-ther-mal- none: gas & electric-ity: BCUC	n/a	none	8000 (at full build out)	Geother-mal- n/a Gas: 7,250 GJ (2010) Electric-ity: 34,305 GJ (2010)	approx. 1650 residents in 600 units	approx. 5500 residents in 2000 units	Master agreement mandates geothermal connections; individual systems are owned by Corix; monthly access fee is not regulated	Sun Rivers geothermal system fees are set by Corix and not regulated; Sun Rivers gas and electricity utility rates are identical to Fortis and BC Hydro rates and regulated by BCUC
Vancouver Southeast False Creek	Heat & hot water from sewer heat recovery (70%) supple-mented by natural gas (30%)	City of Vancou-ver	$32 million	$9.9 million (31%)	7600	58,574 GJ (2010)	166,644 m^2	577,217 m^2 (2020)	Owned and operated by City, managed by Engineer-ing dept; mandatory connection by law; detailed governance and rate setting principles	10% allowed return on 40% deemed equity; rates reviewed and set annually by City Council, 57/43 fixed/ variable rate structure, levelized over 25 years; operating, shortfalls financed by rate stabilization reserve; 2010 rates set at BC Hydro rates plus 10%, annual escalator of CPI + 1.15%

System	Energy Source & Services	Regulator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/yr)	Energy Sales (year)	Connected Floor Space or Customers, 2011	Connected Floor Space or Customers, Full Build-out	Ownership/ Governance	Rate Setting Principles
Prince George Downtown Biomass	Heat and hot water from biomass incineration; natural gas back up	City of Prince George	$14.14 million	$10.16 million (72%)	1868	42,030 GJ (2012)	11 commercial and institutional buildings	not known	Owned by City; operational details TBD; City contract with mill for biomass enabled by bylaw	Individual negotiated capacity charge based on avoided maintenance and replacement cost of the building's gas boilers; 2012 energy charge based on 80% cost of gas ($12.50/ GJ)
Whistler Cheakamus Crossing	Heat and hot water from sewage plant heat recovery supplemented by natural gas	Resort Municipality of Whistler	$4.1 million	unknown (Olympic Village $144 million)	1600	n/a not metered	42,600 m^2 (2010)	85,000 m^2 (2000-2200 residents)	Owned and operated by Whistler as municipal service; not-for-profit; Bylaw sets fees payable by owners of connected building	Unmetered; rate based on unit entitlement basis ($4.58/ m^2 in 2011) set annually to recover forecast operating costs and contribution to replacement reserve fund
Upper Gibsons GeoExchange	Heat, hot water and cooling from ground source (geothermal) system	Town of Gibsons	$1.4 million	$0.83 million (59%)	335	none (2010) not metered	27 residential lots	over 100 residential lots	Owned by Town but under review; mandatory connection bylaw	Rate target of 90% of gas rate; unmetered; basic charge plus individual capacity charge based on heat loss calculation

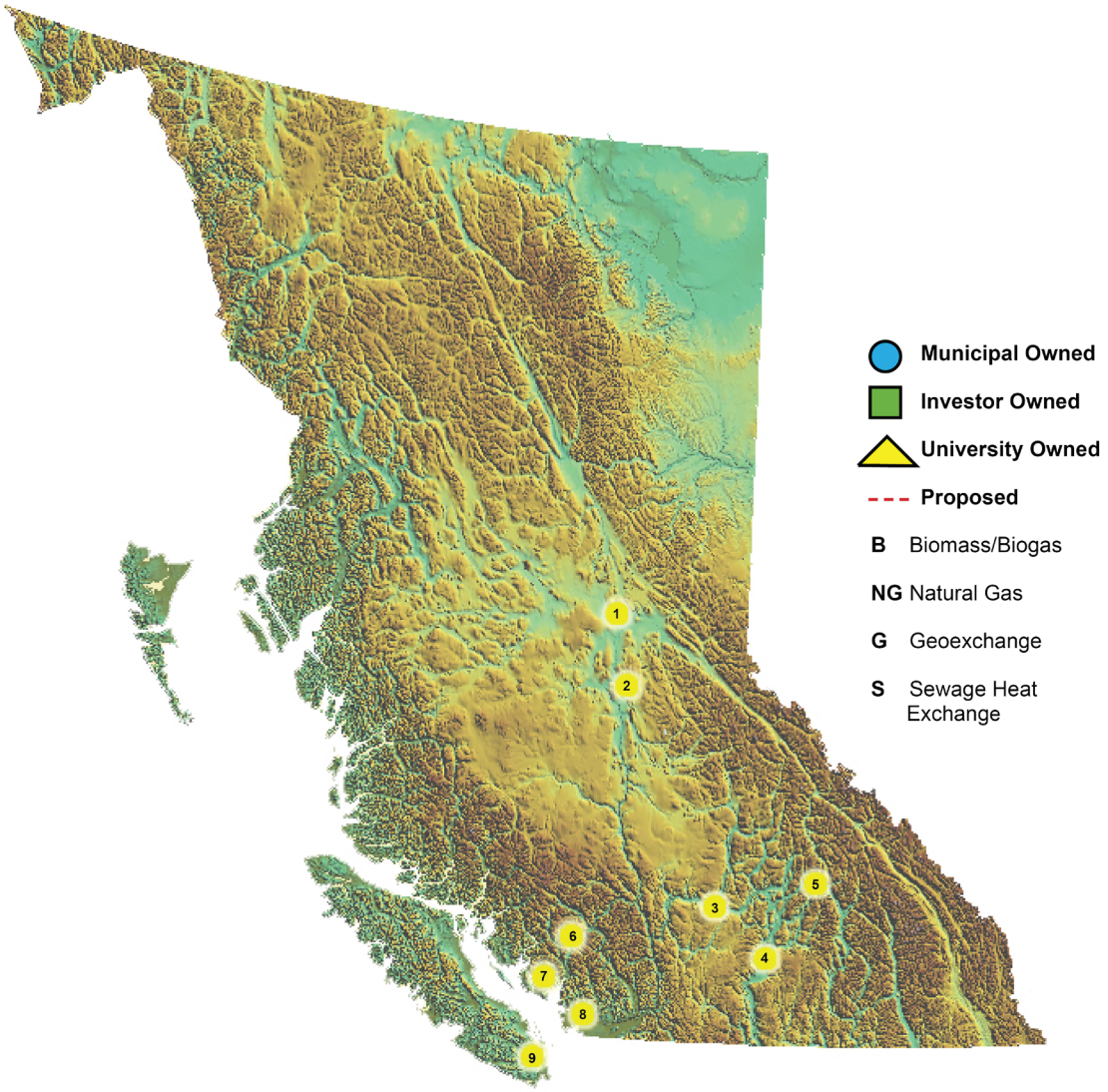
System	Energy Source & Services	Regulator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/yr)	Energy Sales (year)	Connected Floor Space or Customers, 2011	Connected Floor Space or Customers, Full Build-out	Ownership/ Governance	Rate Setting Principles
Westhills Langford GeoExchange	Heat, hot water and cooling from ground source (geothermal) system.	City of Langford	approx. $3 million (phase 1)	none	n/a	n/a	approx. 200 houses	approx. 6000 residents	Water and energy utilities operated by Sustainability Services Ltd; Langford bylaw specifies rates and areas subject to rates	2010 rates identical to BC Hydro inclining block rate; bylaw enables SSL to raise rates by 10% per year.
Other District Energy Systems in British Columbia										
Richmond Alexander (under construction)	Geothermal space heating, cooling and hot water	City of Richmond	$3.5 million (Phase 1)	to be determined	200-600 (Phase 1); up to 6000 (full build out)	n/a	none	362,000 m^2 (3100 residential units)	Owned and operated by City, cost and revenue sharing with private sector; partnered with private sector to design/build; mandatory connection bylaws; density bonuses for developments "in stream" at time of bylaw to discourage electric baseboards	Rate design objective to have end users pay same or less than conventional sources; financially self-sustaining; target 12% return

System	Energy Source & Services	Regulator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/yr)	Energy Sales (year)	Connected Floor Space or Customers, 2011	Connected Floor Space or Customers, Full Build-out	Ownership/ Governance	Rate Setting Principles
Surrey City Centre (under construction)	Geothermal space heating, cooling and hot water	City of Surrey	$4.81 million	feasibility studies only	780	n/a	none	approx. 70,000m^2	Owned by City, operated as a business unit within Engineering Dept.; open to possible future transfer to private sector; rates to be set by law annually	Similar to a private utility (cost of service), including rate stabilization fund and replacement reserve fund
North Vancouver Lonsdale	Natural Gas "mini plants" hot water system for space heating and hot water	City of North Vancouver	$8.0 million	$2.0 million (25%)	4070	n/a	55,700 m^2	up to 335,000 m^2	Owned by City, run as a corporation (wholly owned subsidiary); mandatory connection bylaw; contract with Corix for metering and maintenance; rates set by bylaw	Meter charge, plus a monthly capacity charge ($/KW) plus a gas cost commodity charge (3.78 cents/Kwh in mid 2011)
Revelstoke Community Energy System	Heat and hot water from biomass boiler and propane back-up; steam to sawmill kiln	City of Revelstoke	$7.9 million	$2.2 million (25%)	3700	n/a	approx. ten commercial and institutional customers	depends on system expansion decisions	Owned and managed by City through Revelstoke Community Energy Corp.	Negotiated contracts with ten customers; CPI escalator only; non tax source of City revenue; target ROE of 8.8% over 25 years

System	Energy Source & Services	Regulator	Cost	Subsidy $ (%)	GHG Emission Reduction (tonnes/yr)	Energy Sales (year)	Connected Floor Space or Customers, 2011	Connected Floor Space or Customers, Full Build-out	Ownership/ Governance	Rate Setting Principles
Fortis Quesnel Biomass Combined Heat and Power (Proposed)	Biomass to hot oil to turbine/ generator; hot oil to kilns; DE hot water; DE natural gas back up	BCUC	$14.0 million	$4.1 million ICE Fund (30%)	6000	81,000 GJ (ultimate DE portion)	none	12-22 institutional commercial and residential buildings	Joint municipal/ utility structure (proposed)	To be determined (65% of revenues through proposed 1.7 MW electricity supply contract with BC Hydro)
River District East Fraserlands (Under Construction)	Heat & hot water from natural gas (phase 1) and biomass (phase 2) with gas back up; possible CHP	BCUC	$24.8 million ($10.9 million phase 1)	possible $2 million (BC Hydro, plus possible NR Can, GMF)	8200	18,240 GJ (2034)	none	710,000 m^2	River District Energy LP is a subsidiary of Parklane Group; Vancouver requires a DE systems as a condition of rezoning; CPCN application to BCUC in mid 2011 (phase 1); CPCN approved December 19, 2011 for phase 1	50bp risk premium on 40% deemed equity (10%ROE); 20 year levelized rate structure with deferral account to record early year shortfalls for later recovery; 66/34 capacity/energy charge rate design; first year rate at $88/MW.h; 10% premium over BC Hydro rates accepted

APPENDIX 2: SIGNIFICANT DISTRICT ENERGY SYSTEMS IN BC, 2011

Figure 1 **Significant District Energy Systems in BC** 2011



1. Prince George Downtown (B)
1. Prince George UNBC (B)
2. Fortis Quesnel (B)
3. CORIX Sun Rivers (G)
4. Kelowna UBCO (G)
5. Revelstoke (B)
6. Cheakamus Crossing (S)
7. Gibsons (G)
8. SFU UniverCity (NG/B)
8. UBC (B)
8. Central Heat (NG)
8. Southeast False Creek (S)
8. Richmond Alexandra (G)
8. Surrey City Centre (G)
8. River District Energy (NG/B)
8. North Van Lonsdale (NG)
9. UVIC (NG)
9. Dockside (B)
9. Westhills (G)

ENDNOTES

[1]See for example Community Energy Association, Utilities and Financing at www.communityenergy.bc.ca; and various publications on the Canadian District Energy Association website, www.cdea.ca

[2]"public utility" means 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 […]

but does not include […] a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries […]

[3]See "Fortis BC Energy, Alternative Energy Solutions Inquiry" at www.bcuc.com for Fortis and Intervener Exhibits and Submissions.

[4]A gigajoule is the amount of energy in 278 KW.h of electricity, 915 cubic feet of natural gas, or 29 litres of gasoline. The average BC household uses about 200 GJ a year for heat, hot water, lighting, appliances, and gasoline.

[5]See Damecour, 2008, p.14.

[6]CHDL Response to BCUC Information Request #2, Q.1.1, September 10, 2007.

[7]BCUC Order G-125-07, p.3.

[8]Compass Resource Management, "High Level Review of Sustainable District Energy Options for Northeast False Creek", May 2010.

[9]Compass Resource Management, "Northeast False Creek District Energy Connectivity Study", Report to City of Vancouver and BC Hydro, January 2009. See also "Biomass Availability Study for District Heating Systems", prepared for the BC Bioenergy Network, January 2012.

[10]Adam Hislop, "Clearing the Air: Implications of Biomass Combustion for District Energy in Urban Areas, M.Sc. (Planning) Project, University of BC, August 2010, s. 2.3.

[11]BCUC Reasons For Decision, Order C-7-11, p.2.

[12]Telephone interview with Eric van Roon, Chief Operations Officer, and Ian Wigington, Director, Regulatory and Government Relations, Corix, August 29, 2011; email update from Ivana Safar, Corix, April 24, 2012.

[13]Dockside Green Energy LLP 2009 and 2010 Annual Reports to the BCUC for Biomass Utility.

[14]Corix 2010 Annual Report to the BCUC for the Electric Utility at Sun Rivers Community Resort, Schedule J.

[15]Telephone interview with Eric van Roon and Ian Wigington, August 29, 2011.

[16]Administrative Report on Southeast False Creek NEU Customer Rates, to Standing Committee on City Services and Budgets, December 2, 2010, Table 2

[17]Staff Report to Council, Downtown District Energy System, June 7, 2010, Financial Cash Flow Appendix.

[18]E mails from Gina Layte Liston, Environmental Coordinator, Utilities Division, City of Prince George, February 9 and August 26, 2011.

[19]Whistler Pique, "Cheakamus Residents Concerned Over DE System: Costs Higher Than Anticipated", February 2, 2011.

[20]At a DES supply temperature of 12 degrees C and an air temperature of -3 degrees C, only 20% of the heat is supplied by the effluent; at a DES supply temperature of 10 degrees C, 90% of the heat comes from the effluent.

[21]Victoria Times Colonist, Westshore Supplement, November 2010, quoting Rod Torres, president, Geosource Engineering Corp.

[22]City of Langford Multi Utility Bylaw 1291, 2010, Schedule H, Standard Rate Schedule, S 3(2).

[23]Interview with John Manson, City Engineer, Langford, June 23, 2011.

[24]Notes to Table 1: To convert from MW.h to GJ, divide by 3.6 (1GJ=278 KW.h). Rates include BC Hydro and Fortis basic charges and DE system fixed or capacity charges. Rates exclude HST and Fortis franchise fees, but include the Carbon Tax if applicable ($4.47/MW.h on gas). BC Hydro rate assumes 50/50 split between Tier 1 and Tier 2, includes 8% 2011 interim rate increase, and 2.5% rate rider. DE estimates exclude any strata sub-metering costs.

[25]BCUC Decision on an Application for Approval of the 2008 Long Term Acquisition Plan, July 29, 2009, Section 6.4 (Demand Side Measures); and Review of BC Hydro, June 20, 2011, Section 3.6, p. 114, available at www.newsroom.gov.bc.ca/downloads/bchydroreview.pdf.

[26]BC Bioenergy Network "Austrian Approaches for Successful District Energy Implementation: Mission to Austria February 20-March 4, 2011; Responses to BC Ministry Queries, Section 4.

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