District of Squamish
Neighbourhood Energy Utility
Feasibility Report

FINAL REPORT

Prepared for:

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BC Hydro
City of North Vancouver

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Statement of Limitations

This report has been prepared by Compass Resource Management Ltd (Compass) for the exclusive use and benefit of the District of Squamish with respect to the potential development of a district energy system in central Squamish. This document represents the best professional judgment of Compass Resource Management Ltd. and its partner in this project, FVB Energy Inc., based on the information available at the time of its completion and as appropriate for the scope of work. Services were performed according to normal professional standards in a similar context and for a similar scope of work.

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Executive Summary

Squamish's downtown waterfront is set to undergo a major transition in the coming decades with redevelopment and expansion, including additional housing, commercial space, marina and recreation amenities, and a college. Nearly 6.5 million square feet of new development is anticipated in the downtown core by 2040. At the same time, there is growing interest in Squamish to promote new technologies, increase local resource use, reduce greenhouse gas emissions, and design a more resilient and efficient community.

In 2006, the District of Squamish initiated development of the Community Energy Action Plan (CEAP), which consists of green building policy development, a discussion on regional energy issues, and three catalyst projects that advance energy efficiency, reduce greenhouse gas emissions, and community resiliency. The CEAP process included a pre-feasibility study for a district energy system or so-called Neighbourhood Energy Utility (NEU) to provide central heating using alternative energy sources. The NEU pre-feasibility analysis suggested there was a promising opportunity for district energy in the Waterfront Landing development (the main focus of the pre-feasibility work), with potential for expansion to other areas in the downtown peninsula. Based on these preliminary findings, the District Squamish, in partnership with BC Hydro and Lonsdale Energy Corporation, proceeded to a full feasibility study of an NEU.

District energy offers an innovative and viable opportunity to support Squamish's community objectives. District energy involves the central production of heat (and sometimes cooling and/or electricity), rather than installing separate heating systems in each individual development. In Squamish, large amounts of cooling are not anticipated and so the priority will be on district heating. However, there may be opportunities for a combined heat and power solution.

District energy is an old technology. District energy is very common in many Scandanavian countries, serving more than 50% of total floor area in some countries. There are roughly 6,000 district energy systems in North America today. Many on these systems are on educational, health and military campuses, but there are also many examples of systems serving downtown cores and new subdivisions. B.C. has seen development of several prominent systems in recent years including Southeast False Creek in Vancouver, Whistler's Athlete Village, Lonsdale Energy Corporation in North Vancouver, and Dockside Green in Victoria. Numerous other systems are in the planning and development stages.

District energy offers economies of scale and access to alternative, low-carbon energy sources that may not be economic or available within individual building sites. Equally important, a district energy system also offers a platform for community flexibility and resilience. A central heating plant can better take advantage of new technologies and multiple fuel sources.

This report summarizes the full feasibility study, which was undertaken by Compass Resource Management in association with FVB Energy and Hemmera. The objective of the full feasibility study was to determine the technical and financial viability of an NEU in and around the Squamish downtown that is reliable and competitive with conventional approaches for the provision of space heating and domestic hot water, while improving environmental performance, in particular reducing GHG emissions from the business as usual case. The study was also to give consideration to technologies and fuel sources suitable for combined heat and power.

The feasibility study consists of an analysis of potential heating loads, an assessment of business as usual energy costs, a screening of a wide range of potential alternative energy options, and a more detailed business analysis of three short listed energy options. Biomass energy, ocean heat and cogeneration are the most viable district-scale energy options for downtown Squamish. The analysis shows that with a reasonable level of grants, it would be possible for a system to recover costs and be competitive with on-site heat options.

The analysis suggests biomass energy has the lowest costs and GHG emissions. Biomass energy also has linkages to broader community development objectives. Wood has played a key role in the historical development Squamish and could play an ongoing role in its future evolution. Both ocean heat and natural cogeneration would also offer community benefits, although they would likely require additional optimization and support to ensure their economic viability. Natural gas cogeneration offers a potential stepping stone to a bioenergy cogeneration plant through the future addition of a biomass gasification system.

District energy is a long-term business, not a one-off engineering project. Loads and infrastructure will be added over many years and once a core service area is in place, there may be opportunities for expansion to neighbouring developments. The supply technology will also continue to evolve in response to changing market conditions and new technologies. Future expansions, replacements or upgrades may utilize a different technology than currently contemplated. Many systems will also have the ability to switch among several fuels to take advantage of differences in fuel prices.

The charts below illustrate some of the key dynamics of the business. These charts show expected revenues, operating costs (revenue requirements) and annual capital requirements (before grants). These charts assume a biomass system (which has the lowest capital costs and best financial viability of the systems considered) and assumes a system that eventually serves all the core areas considered in this study (Downtown, Waterfront and Oceanfront Lands). Temporary boilers are used to minimize upfront capital costs while load develops. Once loads reach a critical threshold, the community distribution system is implemented. Similarly, the installation of the biomass system is deferred for several years to allow loads to build to a level that can economically support a biomass plant. At this point the natural gas boilers continue to be used for peaking and back-up energy. This is a common strategy to ensure the viability of a new district energy system.

The revenue projections are based on projections for new development and future electricity rates (used as a benchmark of competitiveness) plus a 10% premium to capture other system benefits such as reduced price fluctuations for heating, occupant comfort, community development, and reduced GHG emissions. The revenue requirements are actual operating costs, including financing and depreciation. In some years, operating costs will exceed revenues but in other years revenues will exceed operating costs. This is typical for a new system. Over the term of the project analysis, the system would recover all costs, including a return on capital.

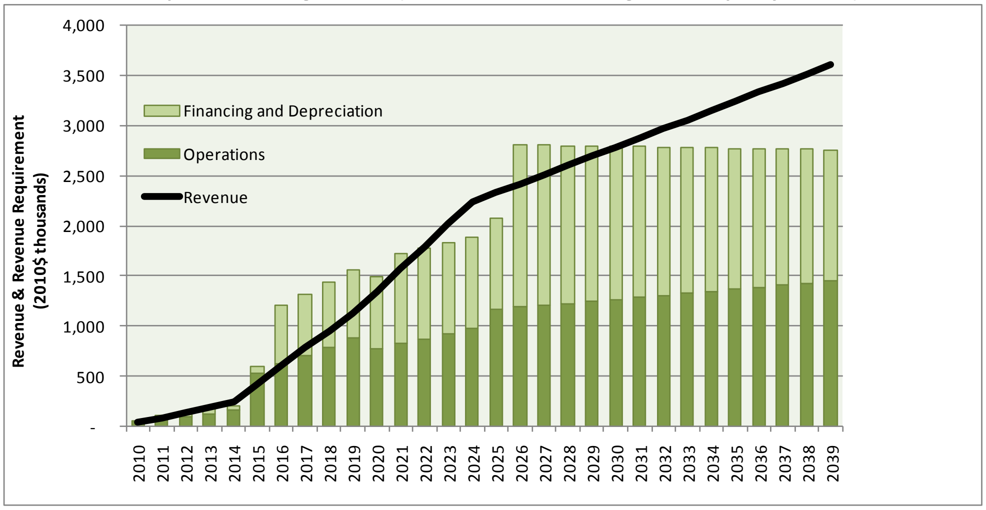
In all cases, an external grant is required to achieve competitive rates and target returns. The required grant is larger under a private finance model reflecting both some additional return required for equity investors (which is regulated by the BC Utilities Commission) and property taxes. The private utility could also be exempted from property taxes, which would not be paid by on-site energy systems. In the case of a municipal finance model, a grant of ~1.3 million dollars would be required to break even. This is well within the types of grants typically attracted by these systems at start-up. In the case of a private utility, a grant of more than $8 million could be required to break even. However, nearly $2 million of this would be required to cover property taxes, which would not be levied in the municipal model or the business as usual scenario without district energy. A private company may also achieve some additional economies in capital investment, operating costs or risk reduction to offset these range requirements.

A final decision on the alternative energy source for a district system is not required for a few years. Natural gas boilers will need to play an ongoing role in peaking and back-up and they should be implemented first until loads reach a sufficient threshold to support an investment in more expensive alternative energy capacity. More immediate decisions are required regarding the target service area, District policies to support development of district energy and secure loads, ownership, distribution system design, and location of an energy centre or centres.

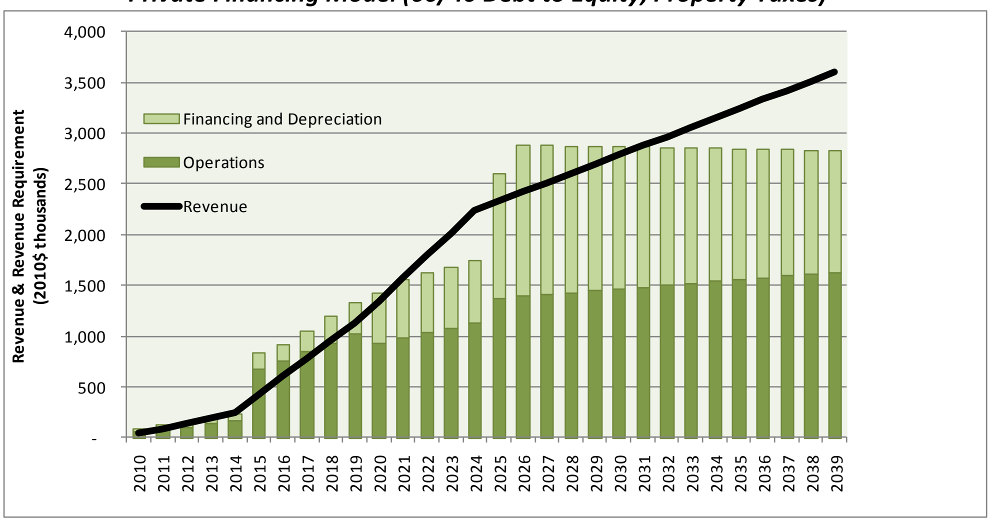
There are numerous ownership options for a system including District ownership, private ownership, a public-private partnership, and a community non-profit structure. Each ownership option offers pros and cons and further dialogue will be required among stakeholders to select the optimal model. Regardless of the final ownership model there will be a critical role for District leadership and policy to support and advance this important initiative.

Illustrative Annual Revenues, Revenue Requirements (After Grants) and Capital Expenditures (Before Grants for a Biomass District Energy System

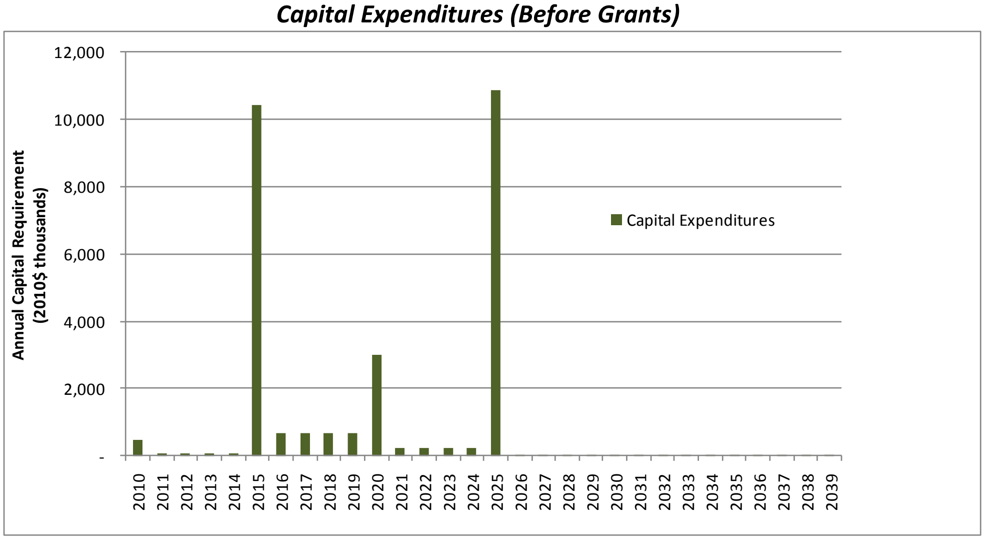
Municipal Financing Model (100% Debt Financing, No Property Taxes)



Private Financing Model (60/40 Debt to Equity, Property Taxes)



Capital Expenditures (Before Grants)



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1.0 Introduction

In 2006, the District of Squamish initiated development of the Community Energy Action Plan (CEAP), that consists of green building policy development, a discussion on regional energy issues, and three catalyst projects that advance energy efficiency, reduce greenhouse gas emissions, and promote community resiliency. The CEAP process included a pre-feasibility study for a so-called Neighbourhood Energy Utility (NEU) to provide central heating using alternative energy sources. The NEU pre-feasibility analysis suggested there was a promising opportunity for district energy in the Waterfront Lands development (the main focus of the pre-feasibility work), with potential for expansion to other areas in the downtown peninsula. Based on these preliminary findings, the District of Squamish, in partnership with BC Hydro and Lonsdale Energy Corporation, proceeded to a full feasibility study of an NEU.

The full feasibility study was undertaken by Compass Resource Management in association with FVB Energy and Hemmera. The objective of the full feasibility study was to determine the technical and financial viability of an NEU in and around the Squamish downtown that is reliable and competitive with conventional approaches for the provision of space heating and domestic hot water, while improving environmental performance, in particular reducing GHG emissions from the business as usual case. The study also considerers technologies and fuel sources suitable for combined heat and power (CHP) applications.

The study involved the following steps:

- Prepare scenarios of future development in five separate subareas of downtown identified by the District of Squamish as candidate service areas for district energy.
- Determine the likely demands for space heating, cooling and domestic hot water in new development based on current and future building code requirements and building practices in Squamish.
- Determine the business as usual costs and GHG emissions for heating in Squamish.
- Identify and screen a wide range of alternative central heating fuels and technologies, including options that may also produce electricity (combined heat and power).
- Select a short list of demand and supply scenarios for more detailed business analysis, including economic, social and environmental impacts.
- Conduct a more detailed analysis of the short listed options.

- Identify implementation issues associated with a district energy system, including ownership options and implications.

Several detailed technical memoranda and presentations were prepared in the course of this study. This report summarizes all key data and findings from these memoranda. Three separate workshops were held with Council and other study sponsors as part of this study: a) a kick-off meeting; b) a review of the preliminary demand forecast and supply screening; and c) a summary of the detailed business analysis.

In addition to the products for Squamish, this study also included an assessment of opportunities to integrate the short-listed technologies into the Lonsdale Energy Corporation's system. This analysis is summarized in a separate technical memorandum to LEC.

2.0 Study Area

Squamish is home to 15,000 residents. It is centered on the Sea to Sky Corridor (Highway 99) between Vancouver to the south and the Resort of Whistler to the north, and is bordered by the Coastal Mountains on the east and the Pacific Ocean on the west. Squamish has a rich history as a logging town and has predominantly been dependent on the forest sector for its economic sustainability, though secondary sectors like transportation and tourism have acted as important drivers in a moderately diverse economy. Squamish is in the midst of rapid socio-economic transformation. Local leaders have been examining and initiating options for economic revitalization and diversification that will lead to positive long-term growth. A variety of opportunities that appear promising are being targeted for serious exploration.

Squamish has witnessed a real estate boom over the past six or more years fuelled primarily by its spectacular natural setting, relative housing prices, upgrades to the Sea-to-Sky Highway, and increased profile after the 2010 Olympics. With local development intensity increasing and the profile of global warming becoming more commonplace, there has been a general consensus within Squamish that the preservation of the natural environment, including GHG mitigation, is important.

Over a number of years there has been growing interest in the District of Squamish that point to a change of course from old ways of using energy, and attempts to stimulate new efficiencies, technologies or designs for a more resilient community, including district energy.

For the purposes of the demand forecast and screening analysis, the NEU study area is divided into five sub-areas or neighbourhoods. Area A was designated as the "core area" because it is central to all five sub-areas and provides a useful stepping off point for a larger system encompassing all five neighbourhoods. The five neighbourhoods are summarized in Figure 1 and described further below.

Core Area A: The Core Area A includes parcels of land between the Mamquam Blind Channel and Loggers Lane from Winnipeg to New Westminster Street, also including two blocks between Cleveland Avenue and Loggers Lane. The Blocks included in the Core Area include Blocks 20, 41, 42, 43, 44 and 45, and a number of smaller infill parcels. The parcels of land are predominantly vacant, with the exception of Block 20 that has existing warehouse uses. Block 20 has an approved Development Permit to redevelop the site with a semi-underground parking structure, 80 residential units, 6,000 sq ft of live work studio and 4,000 sq ft of commercial/other space. The total buildable area of the project is 103,616.8 sq ft and an FAR of 1.39. The DRAFT Downtown Neighbourhood Plan identifies a maximum development Density of 1.75 FAR for the parcels in Core Area A.

Area B: Waterfront Landing. Area B consists of the Waterfront Landing site on the East Side of the Mamquam Blind Channel. The site is approximately 53.1 acres in size and includes 11.2 ha of park / lagoon space. The proposed tidal lagoon is situated in the middle of the site with development around the edge of the lagoon. The proposed use is a mix of residential, retail, commercial and office space. The site is bordered by Blind Channel to the west and north, the railway to the east, and a rock escarpment to the south. The Sub Area Plan and Zoning Bylaw no. 1926 have been approved and permit a range of building forms and densities from Townhouse (FAR of 0.5 – 1.4) to low-rise apartment (FAR of 1.6 – 1.9) to high-rise apartment (FAR of 2.0-2.7).

Area C: Victoria Street Core. This area consists of the part of existing downtown Squamish that is experiencing re-development of aging buildings, and also infill of vacant lots. Area C includes parcels north of Vancouver Street and south of Winnipeg Street, between Loggers Lane and Second Avenue, with one small section of commercial that extends West at Victoria and Third Avenue. These parcels are within the Downtown Commercial (C4) Zone. This zone currently permits residential apartments above commercial/retail/office use and parking. The C4 zone has a current height limit of 6 stories or 66 ft and no maximum FAR, however, the DRAFT Downtown Neighbourhood Plan (DNP) identifies the future FAR for this area between 1.75 to 2.0 FAR. Also worth noting is that to date, the challenge of meeting downtown parking standards (1 stall per residential unit, and one stall for every 500 sq ft of ‘other’ use), no development permit application for Area C has come in over four storeys. As of October 2008, there were just over 300 residential units under application in Area C, with additional development proposals underway. The 2008-09 global credit crunch has put the majority of these projects on hold, however, as financial normalcy returns, it is expected that these developments will resume in a short time span.

Area D: Downtown South - Capilano University. This is the area South of Main Street, bordered by the Squamish Estuary. The area is predominantly zoned Light Industrial (I-1), however, major industrial activity has not occurred in this part of downtown for well over a decade. The most current policy documents identify this area in the Draft Downtown Neighbourhood Plan as a Creative Mixed-Use designation and the Civic Institutional designation. (The Smart Growth on the

Ground concept plan has similar designations). Draft Floor Area Ratios are between 1.5 – 1.75. The major landholder/developer in the Downtown South area at this time is Capilano University, who has secured several larger land holdings in Downtown South against the south and west boundaries of the dike system. Prospective campus development is forecasted to begin in 10 to 15 years. In the interim, smaller and medium scale infill development has been proposed.

Area O: Oceanfront Lands. The Oceanfront Peninsula is located immediately south of downtown Squamish. The planning area, about 33 ha in size, includes the whole peninsula, north to Westminster Street. The site is currently mostly vacant with the exception of some minor light industrial uses. There are three main property owners: the Squamish Oceanfront Development Corporation, BCR Properties Ltd. and Westmana/MOCD (Mamquam Ocean Channel Developments Ltd.). Following the vision and principles in the Downtown Waterfront Concept Plan (2003/04), the Official Community Plan, and the Downtown Sub-Area Plan, Squamish is in the process of development a Sub-Area Plan for the Oceanfront lands that will direct and shape land use, building design, parks and open space, transportation and other infrastructure in the area. This site was added to the study area following the first kick-off meeting given its proximity to the Core Area A, significant development potential and sustainability objectives.

Figure 1: Study Areas

3.0 District Energy Concepts and Background

3.1 Concepts

District energy, sometimes also referred to as neighbourhood energy, involves the central provision of heating and sometimes cooling services. In Canada, central cooling is rarely economic on its own, but may prove competitive where there are very large cooling loads, availability of a low cost chilled water source (e.g., deep water lake or ocean cooling) and/or when service is coupled with district heating to leverage synergies in installation of distribution equipment and central heating and cooling equipment.

There are four main components to a centralized NEU (Figure 2).

Central energy centre(s) – One or more plants produce all of the heating and/or cooling energy required by customers. The central energy plant may also sometimes produce electricity for sale into the provincial grid (combined heat and power).

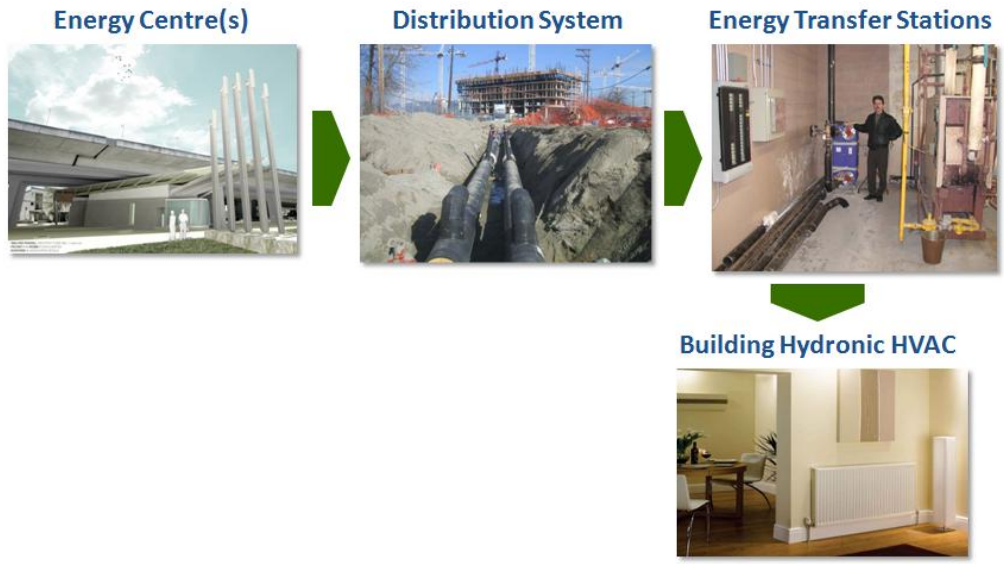
Distribution system – Underground pipes (one supply and one return pipe each for heating and cooling) that distribute hot and cold water to individual buildings.

Energy transfer stations - An assemblage of components located on the customer premises that meter and control the heat energy passed between the NEU and the building. There is typically one ETS per building, although centralization of the ETS is desirable where multiple buildings are under a single owner (e.g., strata). The ETS is owned and operated by the NEU. No other on-site energy sources would normally be required (except on-site chillers in the event centralized cooling is not offered).

In-building Hydronic HVAC Systems – To be compatible with district energy, the in-building Heating Ventilation and Air Conditioning (HVAC) system must be hydronic. Systems inside buildings (Secondary Side of the ETS) remain the responsibility of building developers and owners. These systems must typically be designed to achieve a specified delta T.[1] The internal distribution system should be designed to provide the space heating, cooling and ventilation requirements for the individual suites, hallways/stairwells and other common areas in the building. The DHW system should be designed to provide all DHW requirements for the individual suites, and for all common areas in the building. On-site DHW storage tanks are also typically installed, although instantaneous DHW supply is also possible and can increase overall system efficiency in some cases due to lower return temperatures.

[1] Thermal power is a function of the flow rate and temperature difference. Hot water provided to buildings is returned to the energy center at a lower temperature. Similarly, chilled water provided to buildings returns at a higher temperature after absorbing heat from inside the building. The higher the temperature difference (delta T) the more energy is delivered or absorbed with each gallon of flow.

Figure 2: Components of a District Energy System



New district energy systems typically distribute heat as hot water rather than steam, unless there is a large requirement for steam (e.g., buildings with older heating systems, large laundry and sterilization loads, or industrial processes).[2]

Within individual suites, space heating and cooling may be provided via one of three general approaches at the discretion of the developer: 1) hydronic radiant (e.g., under-floor or ceiling panel); 2) fin type baseboard convectors / perimeter radiators, and 3) fan coils. Fan coils are typically used where both heating and cooling is required, although there are radiant systems that can be used for both. Radiant cooling, however, is relatively new in North America and performance has not been rigorously tested (particularly in residential construction). Radiant heating and cooling systems allow lower supply temperatures for heating and higher supply temperatures for cooling, but these systems also typically have higher capital costs.

Alternative forms of energy can also be delivered by distributed energy systems. These are physically discrete energy systems at the parcel or multi-parcel scale that can be organized under a neighbourhood energy utility ownership model. The main benefit of such a delivery model is that the upfront capital costs are absorbed by the utility and recovered over longer terms through rates. A good example of the distributed model is Sun Rivers near Kamloops, B.C. The utility installed and owns parcel-scale geo-exchange systems and charges residents an access fee for use of the energy system's services. To be compatible with distributed technologies buildings'

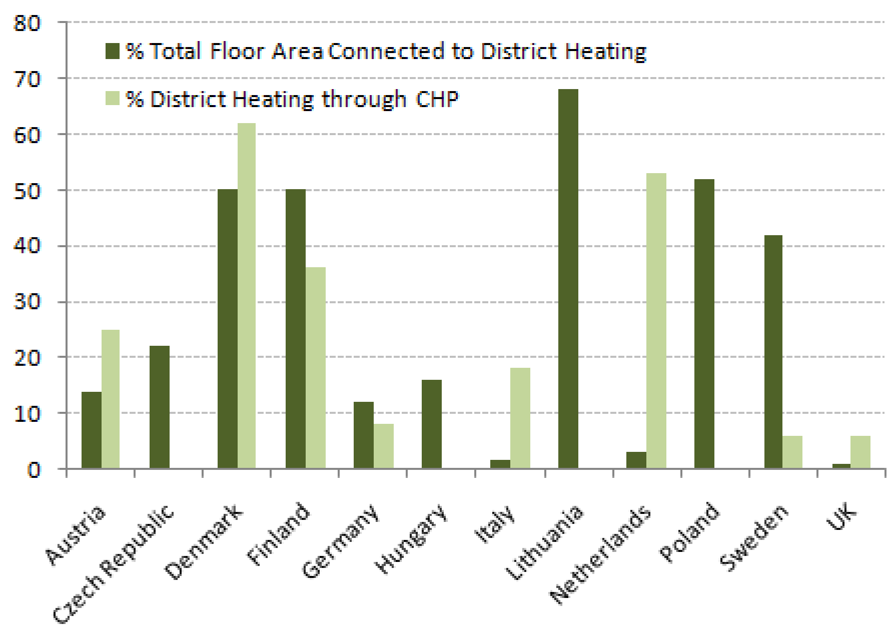
[2] There are also lower temperature concepts that involve uninsulated pipes distributing water at ambient temperatures (5 – 20 degrees C). These systems can be used for both heating and cooling but require on-site heat pumps and peaking / back-up boilers. These types of systems are most suitable in applications requiring both heating and cooling (and with simultaneous heating and cooling) and with access to only low-grade heat sources (e.g., geoexchange systems and/or ocean thermal sources).

internal distribution systems would also have to be hydronic and meet specific design criteria to insure adequate return temperatures.

3.2 History and Current Status

District energy is a very old concept used as far back as the Romans. District energy helped the initial development of the electric power industry by enhancing the economics of new power plants through waste heat recovery. Today, more than 50% of all building stock in some countries of Northern Europe is connected to district energy systems and CHP systems make up a higher portion of district energy systems in countries such as Finland, Denmark and the Netherlands.

Penetration of District Energy in Europe



Source: International Association for District Heating, District Cooling and Combined Heat & Power. Data from 2003. CHP = Combined Heat and Power

There are more than 6,000 district energy systems in North America, most in older downtown cores and on medical, educational or military campuses. There are currently about 120 district energy systems in Canada, with more under development. About one percent of all floor area in Canada is currently connected to district energy, significantly less than many northern European countries. Ontario is currently the leader in district energy, with more than 40% of connected floor space in Canada (~6 million square metres). But district energy is evolving rapidly in other parts of Canada and in particular B.C. District energy service is growing by about 1%/year in Canada.

3.3 Rationale

District energy is a means, not an end. It is another way of providing thermal energy to end use customers and/or electricity to the grid. There has been a renewed interest in district energy as a strategy to capture alternative energy sources such as biomass and waste heat as a means to lower energy costs, reduce reliance on imported fuels (and increase local economic activity), and to reduce greenhouse gas emissions. These benefit both end users and society as a whole.

District energy is not going to be feasible in every urban application. It is generally best suited to higher density sites with planned new development. Proximity to a low cost, high grade heat source (e.g. industrial waste heat) is ideal but tends not to be common in urban settings. Alternatively, the fuel/heat source can be transported from offsite (e.g., biomass, natural gas), stored and processed onsite (biogas via anaerobic digestion) or captured at or near the site in the case of sewer heat and ground source heat pumps.

The pros and cons of district energy are very site specific. They depend on multiple factors including project size, floor area density, development timelines, available district energy sources, and the avoided costs and emissions associated with business as usual building energy systems. Where the right conditions exist, district energy offers potential advantages over conventional building-scale energy systems:

- **Reduced first costs and/or lifecycle costs.** In most cases, a district energy utility pays the upfront capital costs of energy systems and recovers them from users through an ongoing rate.[3] This can be particularly useful in removing first cost barriers to more expensive alternative technologies. In addition, there are benefits from diversification of loads and still economies of scale with many technologies. A professionally managed and focussed district energy utility is often in a better position to maintain equipment, secure lower cost fuel supply contracts, and switch among technologies and fuels in response to changing technology or fuel prices. Utilities often have longer investment horizons allowing amortization and financing rates commensurate with asset life and risks.

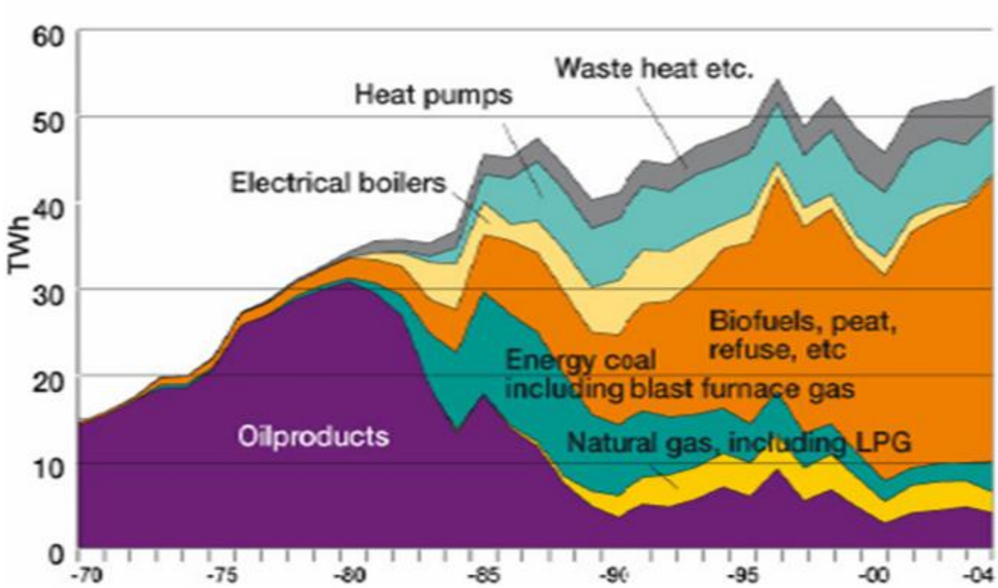
- **Improved quality of service.** District energy systems provide a high quality of service. There is central redundancy and back-up. As a result, district energy systems have often run through major outages of the electric grid as occurred during recent black-outs and catastrophic events in Toronto, Montreal, the eastern U.S. seaboard, and San Francisco. Individual stratas no longer need to deal with equipment maintenance and have a service provider to call in the event of problems. Hydronic heat, particular in the form of hydronic baseboard or in-floor radiant systems, is often considered more comfortable by customers than electric heat.

[3] One exception is where the customer pays a capital contribution to the system upfront.

- **Improved environmental performance.** The economies of scale and integration associated with district energy systems can be partially used to invest in better performing equipment. Centralized systems sometimes have access to alternative resources not currently available at the scale of individual buildings including larger waste heat sources, biomass, and CHP. Professional maintenance of equipment ensures optimal operation and can reduce efficiency degradation rates over the life the assets. District energy owners have an ongoing incentive to find and implement cost savings through regular maintenance, efficiency upgrades, switching technologies or fuels.

- **Reduced risk and increased flexibility.** District energy can offer immediate benefits to customers through reduced exposure to fluctuating fuel prices as a result of higher efficiency and/or fuel switching capability. A district system also pools the risk of alternative technologies across a larger number of users, compared with the implementation of stand-alone building systems. Perhaps ones of the greatest societal benefits of district energy is that it provides a large-scale platform for the future adoption of new fuels and technologies in the future, contributing to the long-run adaptability and competitiveness of an economy. The Swedish experience illustrates the potential flexibility of centralized systems (Figure 3). Since the 1970s, the penetration of district energy has nearly tripled so that nearly 50% of the building area in Sweden is now supplied with district energy. Over this same period, district energy systems in Sweden have transitioned from relying almost entirely on imported fuel oil to relying on a diverse mix of resources, including biomass, refuse and waste heat. In between, there were periods in which coal and electricity were more dominant sources of heat. It is unlikely such a large and relatively rapid switch in fuels and technologies would have been possible if buildings had been heated by thousands of smaller plants.

Figure 3: Swedish District Energy Experience (1970 – 2004)



Source: Swedish Energy Agency

Mature district energy systems also offer an alternative revenue source to municipalities, either through direct ownership or municipal taxation of assets, particularly where the costs of district energy are less than alternatives. In addition, greater reliance on local resources can create local jobs and stimulate more local economic activity.

3.4 Key Challenges for District Energy

While district energy offers the potential for low cost and environmental improvements compared to business as usual systems, it required collective action to secure these benefits. The situation is comparable to the early days of the electric power industry, which required monopoly service areas to secure the economies of scale necessary for cost-effective development of electricity systems. Some of the typical challenges faced by district energy, particularly at start-up include the following:

- **Staging of capital.** Some district energy capital is lumpy and must be staged carefully to minimize carrying costs prior to securing revenues and to minimize stranded investment risk. There must also be acknowledgement and acceptance among stakeholders of strategies to reduce these risks, including interim reliance on peaking and back-up boilers until loads reach sufficient levels to support investment in alternative technologies.

- **Revenue risks.** Customer capture and retention is critical to ensuring economies of scale and minimize stranded capital risks. These risks can be reduced by policies and bylaws to secure loads and by optimizing the staging and siting of equipment relative to loads.

- **Building performance.** Buildings connected to district energy must be properly designed, commissioned and maintained to ensure optimal operation of the district energy system. Strategies to ensure good building performance include providing design guidance and commission support to developers, requiring security deposits to ensure good design and full commissioning, and providing support to retrofits of existing buildings.

- **Coordination.** Considerable coordination among land use and infrastructure planning is required to minimize implementation costs, secure energy production sites, and secure certain alternative energy sources such as waste heat sources. Building codes and enforcement can be used to promote voluntary connection and ensure system performance. Careful coordination with building developers and designers is required to ensure optimal system compatibility.

- **Supply and price of alternative technologies and fuels.** Supply chains for some alternative technologies and fuels are not yet well developed, and there may be both supply and price risks compared to well-established conventional fuels. Building flexibility to accommodate multiple technologies can be an important strategy to mitigate these risks. The use of competitive tendering and performance contracting can also help to transfer some of the risks of new technologies to vendors.

- **Level and certainty of cogeneration electricity price.** The primary focus of district energy utilities is on the provision of heating (and sometimes cooling) service. Cogeneration is also an option but the level and certainty of electricity prices can reduce their incentives to pursue cogeneration alternatives.

3.5 Case Studies

We prepared three case studies to help illustrate some of the opportunities and issues associated with district energy. Each case study reflects different technologies and ownership models. More detailed descriptions are contained in Attachment A to this report.

3.5.1 Southeast False Creek, City of Vancouver, BC

South East False Creek (SEFC) is an 80-acre waterfront industrial brown field site near downtown Vancouver. In March 2005, Vancouver City Council approved an Official Development Plan for a sustainable, mixed use community. SEFC will eventually contain about 6 million square feet of development (approximately equivalent to the anticipated development in downtown Squamish by 2040). About

90% of floorspace will be residential with a population of approximately 16,000. A 15-year development timeframe is currently anticipated for the full site. Phase 1 of the development is home to the Athlete's Village for the Vancouver 2010 Winter Olympics. The Village will be converted to market and social housing post-games.

As one tool to achieve its sustainability goals, the City of Vancouver created the Southeast False Creek Neighbourhood Energy Utility (SEFC NEU) to produce and distribute hot water for space heating and domestic hot water in buildings. There were three key goals for the creation of NEU: provide reliable, comfortable and cost competitive thermal energy; lower GHG emissions; and reduce the use of high-quality energy (electricity) for the provision of low-grade space and hot water heating.

The SEFC NEU draws low-grade heat from the sewer system, and uses centralized heat pumps to provide high-grade heat to customers. The system began operating in early 2010, and is able to add additional capacity as further development takes place in Southeast False Creek.

3.5.2 Markham District Energy, Markham, Ontario

Markham District Energy (MDE) is a district energy utility that is a wholly owned subsidiary of the City of Markham. The system serves the emerging Markham Centre at Highway 7 and Warden Road, north of Toronto. The utility delivers heating and cooling energy to nearby residential, commercial, institutional and public buildings. Electricity is also generated and fed into the grid with the waste heat directed to the district energy system for additional thermal energy.

MDE became operational in 2001, providing heating and cooling service from the first of four planned energy plants to 3 buildings consisting of 90,000 m2. These anchor tenants were critical for the creation of a viable system. Similar to most utilities, district energy systems require large capital outlays which are recovered over time through customer rates. A large customer base in the early years of system inception can help propel a favourable business case (see Effects of Phasing section in Economic Analysis section of this report).

Currently, MDE serves or has signed long term contracts with all new buildings planned to date in the Markham Centre. In total, approximately 500,000 m2 will be connected, including two community and school buildings, six commercial buildings, fourteen residential highrise buildings, and 175 town-homes. Presently, the system serves approximately 70,000 m2 of residential and 120,000 m2 of commercial.

The ongoing development of MDE is closely tied to the City's vision for a sustainable Markham Centre. Planning for City Centre began in the 1990s and continues today. The Centre vision – described as an environmentally sustainable, transit-friendly, and attractive suburban downtown – will be home to 25,000 residents and provide job space for up to 17,000 employees at the completion of a 20-30 year buildout. Central to the vision of Markham Centre is an efficient, district energy system that serves all of the anticipated 2 million m2 of mixed use floorspace.

3.5.3 District Energy St. Paul, Minnesota

District Energy St. Paul (DESP) started off as a demonstration project in 1983. The initiative was spearheaded by then Mayor George Latimer, who lobbied state and federal governments for assistance in replacing a former steam system with a modern district energy system. The system was designed to be energy efficient, provide local fuel flexibility, and secure stable rates for customers. It was developed through a public/private partnership among the City of Saint Paul, State of Minnesota, U.S. Department of Energy and the downtown business community. DESP is a not-for-profit corporation with a board of directors comprised of both government and customer-appointed members.

In 1993, DESP began offering district cooling service to downtown building owners. In 2003, DESP developed an affiliated combined heat and power (CHP) plant fuelled by urban wood waste. It is one of the largest biomass-fired systems in North America. Capacity and service area has grown steadily over time, and as of 2010, DESP has 289 MW of heating capacity and annual heat sales of over 300,000 MW.h. DESP serves ~185 buildings and 300 single-family homes (2.8 million square metres) and cools ~95 buildings (1.7 million square metres) in downtown St. Paul and adjacent areas. DESP now serves twice as much building area as the former steam system it replaced while consuming the same amount of fuel. Rates have been relatively stable and generally below the cost of on-site natural gas heat production.

This system has successfully capitalized on many of the technical advantages of district energy. With the construction of a biomass-fuelled CHP plant in 2003, District Energy was able to switch fuel sources to a GHG-neutral resource, reducing its reliance on coal and increasing its overall efficiency by capturing otherwise wasted energy and using it to generate electricity. Fuel switching and adoption of new technologies is easier with neighborhood-scale heating plants than building-scale systems. Coordinating individual owners can be difficult and time-consuming, and they are not likely to have the same technical and operational resources as a neighborhood-scale plant.

DESP's governance structure, with its involvement of local government alongside system customers, is an example of how a neighborhood-scale utility can facilitate cooperation to address community concerns. As a non-profit corporation, District Energy's primary mission is not to enhance shareholder value, but "to be the preferred provider of community energy services that benefit our customers, the community and the environment."

4.0 Demand Forecast

The starting point of the study is a demand forecast. The demand forecast is developed from projected floorspace and Energy Use Intensity factors. The forecast considers both projected annual energy and peak loads. Detailed assumptions and analysis underlying the demand forecast are contained in a separate technical memorandum. This report summarizes the key inputs and outputs from the demand analysis.

4.1 Floorspace Estimates

All future thermal loads are assumed to be from new construction on the site. Existing floorspace is not included in the screening or business analyses because much of the existing stock will be redeveloped and the connection of existing loads is more complex.[4] Once there is a commitment to proceed with an NEU we recommend additional consideration be given to opportunities to capture existing loads as further optimizations of the business case during the detailed design and implementation phases.

Planning staff for the District of Squamish provided high and low scenarios for future floorspace for all five neighbourhoods included in the study. We used the average of the high and low scenarios for the purposes of the supply screening and business analysis (Table 1). The difference between the average and the high and low estimates is about +/- 20% by 2040. The total expected development across all five neighbourhoods in the next 30 years is about 625,000 m2. This is roughly equivalent to the total floor area planned for the Southeast False Creek area of Vancouver (the

[4] There is about 80,000 m2 of existing development in the five study areas, of which 60,000 m2 is expected to be redeveloped in the next 30 years.

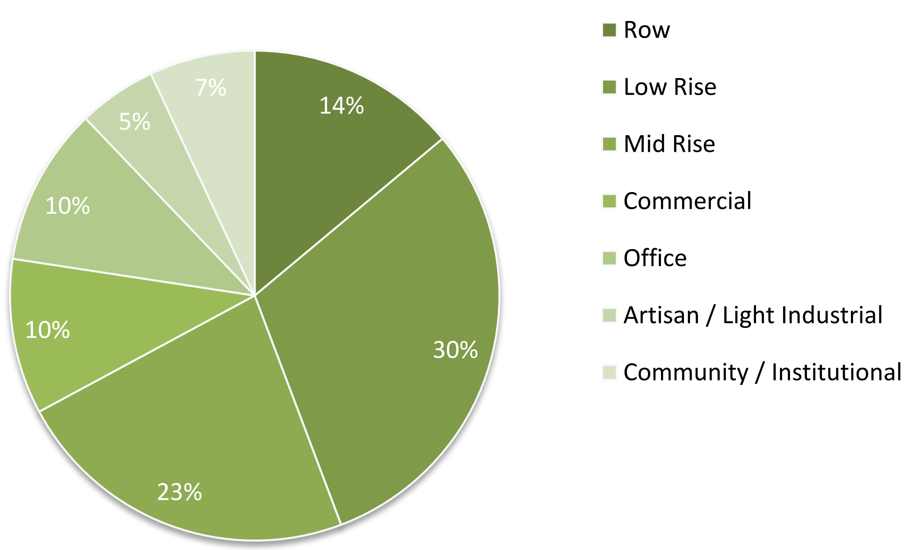
location of Vancouver's Olympic Village) which recently implemented a district energy system.

Table 1: Cumulative New Floorspace Estimates (Average) (m2)

	2015	2020	2025	2040	% Share
Area A	22,600	90,300	101,600	111,700	18%
Area C	6,300	25,200	37,800	51,600	8%
Area D	1,200	55,500	74,000	86,300	14%
Area O: Oceanfront	10,900	36,300	127,100	236,000	38%
Area B: Waterfront	4,700	31,000	77,600	139,700	22%
Total	45,700	238,300	418,100	625,300	

About 40% of the total expected new floorspace in 2040 is located in the Oceanfront Lands. The Waterfront Lands and Area A represent 22% and 18%, respectively, of the total. However, in the near term most growth will be in Area A and Waterfront Lands. The Oceanfront Lands are assumed to develop later in the planning horizon. The majority of anticipated development is residential (~70%), with a mix of commercial and retail uses making up the balance (Figure 4).

Figure 4: Expected Use Mix (2040)



4.2 Energy Use Intensity Factors

Energy demands are estimated using Energy Use Intensity factors (EUIs) modelled for each building type. EUIs reflect the Squamish climate and new BC Building Code. Specifically, Part 3 (larger commercial) buildings are constructed in accordance with ASHRAE 90.1-2004. Part 9 (small residential and simple commercial) buildings are constructed to an Energuide 77 rating. EUIs for both peak and annual demand are summarized in Table 2. These represent end use energy requirements– i.e., the amount of final space heating, space cooling and DHW service that is required. The actual type and amount of fuel used to supply these end uses would depend upon the specific kind and efficiency of equipment used in the building. The end use requirement is required to determine the amount of supply needed from district energy in the absence of on-site boilers and other equipment.[5] Space heating reflects both space heating loads within individual suites or commercial spaces, as well as building ventilation loads. From recent audits conducted in the Lower Mainland ventilation loads can account for 30 – 60% of the total space heating load in multi-unit construction (shared corridors).

Table 2: Energy Use Intensity Factors

	Row	Low Rise	Mid Rise	Commercial	Office	Artisan/ Industrial	Community/ Institutional
Space Heat [W/m2]	36	48	55	30	55	55	55
Space Heat [kW.h/m2]	35	37	67	36	58	58	58
DHW [kW.h/m2]	30	30	30	8	8	8	8
Space Cool [W/m2]	24	48	78	28	60	28	56
Space Cool [kW.h/m2]	5	19	32	31	33	31	57
Cooling penetration	5%	5%	5%	100%	100%	100%	100%

For the purposes of this study we assume constant EUIs over the planning period. Many anticipate further code improvements but we note that B.C. only recently added energy performance to the provincial building code after many years of consideration. Furthermore, recent audits of buildings of various ages in the Lower Mainland found that actual building performance has not changed greatly. Although there have been some improvements in building practices and technologies, these

[5] Building codes typically focus on envelope or equipment performance. Energy reductions are measured in terms of fuel input. Fuel use for heating and cooling can be reduced through a combination of envelope improvements and equipment selection. In order to estimate the amount of district energy that may be required, we need to make assumptions about how much of the code requirements will be met through envelope improvements. Our assumptions in this study are based on current practice and economic estimates of the relative cost of envelope improvements vs. equipment upgrades in meeting the latest code requirements.

seem to have been offset by additional energy demands. The estimates in Table 2 may also be considered conservative as they assume a low glazing (window) ratio (40%) and do not include unique and site-specific building demands such as pools and recreational amenities.[6]

4.3 Site Energy Demand

Table 3 summarizes the estimated thermal demand for each neighbourhood at build out. Table 4 summarizes the expected combined demands across all five neighbourhoods by year. The estimated thermal energy demands reflect the floorspace and EUI assumptions above.

We consider only thermal demands (heating and cooling). Other electric loads are not included in this analysis. These are not the focus of district energy. Even if a combined heat and power plant were developed, the electricity would most likely be sold to BC Hydro and would form one of many resources in the local supply grid.

The diversified peak demands reflect the effect of load diversification. When individual buildings are aggregated and served by a single system, the total capacity required in the central system is typically lower than required if plants are distributed in individual buildings because the peaks for different buildings and use types occur at different times. This is one of the benefits of district energy. We assume diversification factors of 85% for space heating and cooling. The DHW load is assumed to be fully diversified (i.e., does not contribute to the system peak). This is consistent with the diversification factor seen on other systems, including Lonsdale Energy Corporation.

We assume low penetration of residential cooling in Squamish. Cooling is currently not common in residential spaces and local developers and designers indicated that in many cases passive design features would be adequate and preferable to mechanical cooling. We assumed 100% cooling penetration in commercial spaces for simplicity. As a result, cooling represents less than 20% of the annual energy loads for Squamish. For this reason, we excluded cooling from further analysis except as part of the sensitivity analysis for certain energy sources (e.g., geoexchange and ocean energy).

[6] It is also important to note that equipment capacity requirements have declined less quickly than annual energy requirements. Capacity is a major determinant of the capital cost and lifecycle cost of both on-site and district systems.

Table 3: Thermal Energy Demands at Buildout (By Neighbourhood)

	Area A	Area C	Area D	Oceanfront	Waterfront	Total
Floor Area (m2)	111,700	51,600	86,300	236,000	139,700	625,300
Annual Heating (MW.h)	7,600	3,100	5,500	17,400	11,400	45,200
Peak Heat (MW)	5.3	2.4	4.1	11.7	6.6	30.1
Peak Heat Diversified (MW)	4.5	2.0	3.4	9.9	5.6	25.5
Annual Cooling (MW.h)	1,100	1,200	1,700	3,400	500	7,900
Peak Cooling (MW)	1.6	1.6	2.0	4.0	0.7	9.9
Peak Cooling Diversified (MW)	1.3	1.4	1.7	3.4	0.6	8.4

Table 4: Thermal Energy Demands by Year (All Neighbourhoods)

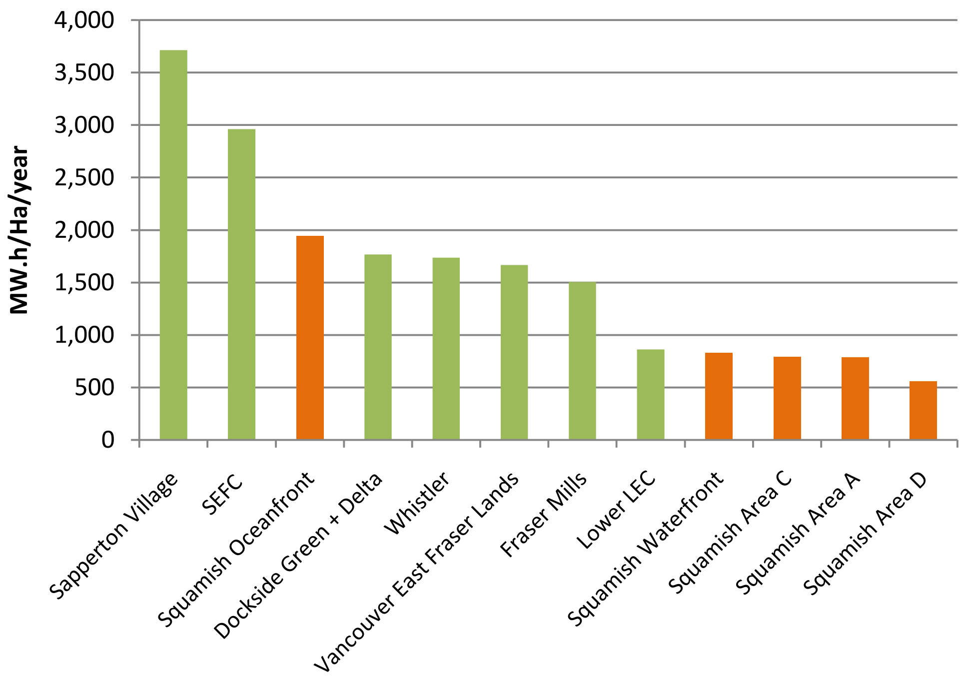
	2015	2020	2025	2040
Annual Heating (MW.h)	3,200	16,500	29,700	45,200
Peak Heat (MW)	2.2	11.3	20.0	30.1
Peak Heat Diversified (MW)	1.9	9.6	17.0	25.5
Annual Cooling (MW.h)	600	3,200	5,400	7,900
Peak Cooling (MW)	0.7	4.1	6.9	9.9
Peak Cooling Diversified (MW)	0.6	3.5	5.8	8.4

There are many factors that influence district energy viability. One consideration is development and by association heating density. All things being equal, higher densities will improve the viability of district energy because there will be a greater ratio of demands to distribution capital. There is no single threshold for viability since other factors will also be important, including the cost of available heat sources and overall scale/rate of development. However, district energy, particularly in jurisdictions such as Canada, is rare in low density single family or attached housing neighbourhoods.

Figure 5 compares the heat energy density at build out of each of the five neighbourhoods in this study to other neighbourhoods that have a district energy system or are pursing one. The comparisons reflect gross floor space and site area. The presence of parks and overall site layout can also influence the ratio of distribution costs to heating loads. However, based on this simple comparison, Oceanfront has the highest proposed energy density of the five neighbourhoods, while Area D has the lowest. Waterfront, Area C and Area A are comparable to areas served by Lonsdale Energy Corporation in the City of North Vancouver.

Following the supply screening below, we chose to focus the more detailed business analysis on only Core Area A, Waterfront and Oceanfront loads. Both Oceanfront and Waterfront will be completed redeveloped and this is the best opportunity to consider district energy. Area A is central to Waterfront and Oceanfront and could be a good bridge between the two. Much of the redevelopment in Area A will be in a relatively linear waterfront corridor, and redevelopment in Area A will likely be complete earlier than both Waterfront and Oceanfront. Development in Areas C and D will be more dispersed. However, once a decision to proceed with the core system is made, extensions into Areas C and D should be considered in the detailed design and ongoing implementation phases on a case by case basis.

Figure 5: Energy Density Comparison (MW.h/ha/year)



5.0 Business as Usual (BAU) Analysis

The BAU analysis serves as a benchmark for determining the economic viability and environmental or social benefits of district energy.

5.1 Typical HVAC Practices in Squamish

We developed BAU HVAC practices using our knowledge of typical construction practices and information from BC Hydro's Conservation Potential Review. We also consulted with District building officials to confirm these assumptions. Typical building practices and equipment efficiencies in Squamish are summarized in Table 5.

Table 5: BAU HVAC Equipment

	Space Heat			MAU (if applicable)			DHW	
	Equipment	Efficiency		Equipment	Efficiency		Equipment	Efficiency
Commercial	Packaged roof top unit	80%		Packaged foor top unit	n/a		Electric storage tank	84%
Row	Furnace	92%		Principle exhaust fan for two-4 hour cycles	n/a		Electric storage tank	84%
Low Rise	In suite electric baseboard	100%		Roof-top MAU	80%		Central tank (gas fired)	75%
Mid Rise	In suite electric baseboard	100%		Roof-top MAU	80%		Central tank (gas fired)	75%

Notes: A Make-up air unit (MAU) provides ventilation air. Efficiencies reflect seasonal efficiencies over an entire year reflecting equipment cycling and partial loading conditions.

For the purposes of the BAU analysis, we assume any cooling is provided via electric chillers with a coefficient of performance of ~5.

5.2 Fuel Price Assumptions

Because we are considering long-lived investments, we use forecasts of future fuel prices in both the screening and business analyses. We use levelized fuel prices for simplicity. A levelized price is a way of converting a forecast into an equivalent constant price taking into account a discount rate.[7] We use <u>real</u> levelized prices, which are constant prices before adjusting for inflation (i.e., all prices are in $2010).

BAU costs are a function of both capital and operating costs. Gas is cheaper from an operating cost perspective but we must also include the capital costs of gas-fired equipment. Capital costs are more complex to estimate and value from a consumer perspective. Electric resistance heaters also have a capital cost but their cost is typically very small in comparison to gas-fired systems. Based on recent studies conducted in the Lower Mainland the lifecycle costs of gas and electricity heat, taking into account both capital and fuel costs, is currently very similar. Furthermore, given more than 70% of the expected load in the NEU is residential and electric heat is most common form of space heating, we use electricity prices as a proxy for the cost of heating in both the screening and business analyses.

Electricity prices are set to escalate rapidly in B.C. Rates have already increased about 20% in the past four years. Accordingly to a long-term rate forecast filed with the BC Utilities Commission, BC Hydro projects further increases of nearly 30% *above inflation* over the next five to seven years. These rapid increases are a function of several factors including system expansions to serve ongoing load growth,

[7] For BAU electricity prices we assume a 10% real customer discount rate. Studies of consumer behaviour suggest people use even higher discount rates when comparing the upfront cost of more efficient equipment with future savings. We use 10% to be conservative. However, this points to one of the benefits of a utility model in which capital is recovered from customers over time through a utility rate.

maintenance of major infrastructure added in the 60s and 70s, and environmental commitments necessitating the use of higher cost alternative energy sources. Many of the low cost resources in B.C. were developed 30 – 50 years ago and new resources are more costly.

In addition to general rate increases, BC Hydro has also implemented stepped rates for residential customers and is in the process of implementing flat and stepped rates for commercial customers. Stepped rates result in higher prices for consumption above a certain baseline. Electric heat can be enough to push a customer over the baseline where so-called Tier 2 rates apply. For electric heat, we assume an average blended cost based on 80% at Tier 1 and 20% at Tier 2.[8] Because district energy provides numerous intangible benefits such as improved comfort, high reliability, environmental benefits, and reduced exposure to increasing and volatile fuel prices, we also consider a premium of up to 10% over electricity in the analysis. This is consistent with the approach used to test economic viability and set rates for the NEU recently established for the Southeast False Creek neighbourhood in the City of Vancouver.

All of our levelized fuel price assumptions for this study are summarized in Table 6. For simplicity we have converted all fuel prices into a common energy unit of MW.h. All fuel prices include the BC Carbon Tax, where relevant. As the provincial government has made no commitments to increase the carbon tax above $30 / tonne by 2012, we have assumed no further escalation in carbon taxes. The natural gas price assumptions reflect Terasen delivery charges and a publicly available forecast of natural gas commodity costs from Sproule Associates Limited. Commercial rates normally include demand charges. For simplicity, we have estimated average unit rates based on the typical load profile for heating.

We have also included a price estimate for the value of electricity from a cogeneration plant for screening cogeneration options. The price in Table 6 reflects the current BC Hydro Standing Offer for small-scale generation (<10 MW). The Standing Offer price varies by region and is also weighted by hour and month. The price in Table 6 reflects a weighted average price for a cogeneration unit with 4,500 to 5,500 run hours allocated to the heating season. In order to qualify under the Standing Offer, a natural has cogeneration unit would have to achieve a ~80% overall efficiency requiring it is sized and dispatched for heating. It is important to note the Standing Offer price is likely to increase with the higher average prices from the recent Clean Call and future increases in the Tier 2 rate for industrial and residential electricity. Furthermore, BC Hydro has conducted dedicated calls for biomass-fired cogeneration systems which have resulted in higher prices. We have therefore conducted sensitivity analyses around the Standing Offer price.

[8] RDH Engineering recently completed a study of actual energy consumption in Multi-Unit Residential Buildings in the Lower Mainland and found 80-85% of heating electricity is consumed in the step 1 rate and 15 - 20% in the step 2 rate across the entire sample.

The biomass price is based on the expected average heating value of green wood waste. Biomass supply and pricing is discussed further in the business analysis below.

Table 6: Levelized Fuel Price Assumptions ($2010)

Fuel	Unit	Levelized Price
Natural Gas (Carbon Tax Included)		
Rate 3	$/MW.h	41
Cogen Levelized Gas Price (Rate 5 or 22)	$/MW.h	38
Electricity		
Residential Inclining Block		
Step 1	$/MW.h	79
Step 2	$/MW.h	110
Blended	$/MW.h	83*
Commercial - Blended	$/MW.h	66
Standing Offer Purchase price	$/MW.h	90 - 95
Biomass	$/MW.h	10 - 20

*Including a 10% premium the blended rate is $91/MW.h. It is important to note that there are rapid increases in electricity prices anticipated in the next 7 years. We have estimated levelized electricity prices from today forward. Assuming a project start date of 2013 or beyond, the comparable levelized price of electricity from that point forward is $88/MW.h. We are therefore being somewhat conservative in this analysis.

5.3 BAU Fuel Consumption and Heating Costs

Table 7 and Table 8 summarize estimated fuel consumption under BAU assumptions for HVAC equipment type and efficiency. For BAU fuel consumption we assume natural gas is used for all commercial space heating, all mid rise DHW and 50% of all residential space heat. Electric space heating is common for low and mid rise apartments with a natural gas make up air unit for hallways and common areas. However, a recent analysis that assessed the energy use of multi-unit residential buildings in the Lower Mainland found that majority of the space heating requirements in units with electric baseboard heating is being met by natural gas heating, either from the hallways or gas fireplaces.[9] We took a conservative approach and assumed 50% of all residential space heating requirements are met with natural gas. We assume electricity is used for the remaining 50% of residential space heating and for all DHW supply in rowhouses.

[9] RDH Building Engineers Ltd. (2009). Energy Consumption and Conservation in Mid and High Rise Residential Buildings in British Columbia. Report #1: Energy Consumption and Trends. Draft version (10-Feb-09). Project # 3033.00.

Table 7: BAU Fuel Consumption All Neighbourhoods by Year (MW.h)

		2015	2020	2025	2040
Heating					
Electricity	MW.h	900	4,700	8,800	13,700
Natural Gas	MW.h	2,800	14,600	25,900	39,000
Cooling					
Electricity	MW.h	200	1,000	1,700	2,500
Total					
Electricity	MW.h	1,100	5,700	10,500	16,200
Natural Gas	MW.h	2,800	14,600	25,900	39,000

Table 8: BAU Fuel Consumption at Build Out by Neighbourhood (MW.h)

	Area A	Area C	Area D	Oceanfront	Waterfront	Total
Heating						
Electricity	2,100	700	1,500	5,100	4,400	13,700
Natural Gas	6,800	3,100	5,200	15,200	8,600	39,000
Cooling						
Electricity	300	400	600	1,100	100	2,500
Total						
Electricity	2,500	1,000	2,000	6,200	4,500	16,200
Natural Gas	6,800	3,100	5,200	15,200	8,600	39,000

Table 9 summarizes the total estimated cost of heating on a $/MW.h and $/m2/year basis using electric heat as a proxy. Changes in the cost per m2 over time reflect changes in use mix and usage characteristics of different types of floorspace. Residential floorspace is generally more heat energy intensive than commercial uses.

Table 9: Cost of Heating at Buildout

		2015	2020	2025	2040
Levelized Cost of Heat	$/MW.h	$91	$91	$91	$91
Heat Fuel	MW.h/year	3,724	19,323	34,720	52,653
Floorspace	m2	45,648	238,281	417,991	625,346
Cost of Heat	$/m2/year	$7.45	$7.41	$7.59	$7.69

5.3.1 BAU Greenhouse Gas Emission Assumptions

The environmental evaluation consists of comparing the greenhouse gas (GHG) emissions of district energy options to BAU heating options. The GHG analysis is based on the fuel consumption estimates above. The emission factor used for electricity is 22 kg/MW.h and 180 kg/MW.h for natural gas (based on fuel input).

Table 10: Cumulative BAU GHG Emissions at Build Out (tonnes/year)

	Area A	Area C	Area D	Oceanfront	Waterfront	Total
Heating	1,300	600	1,000	2,900	1,700	7,300
Cooling	10	10	10	20	0	50
Total	1,300	600	1,000	2,900	1,700	7,400

6.0 Screening Analysis Summary

The purpose of the screening analysis is to identify and evaluate a wide range of alternative energy sources in order to identify the most promising candidates for more detailed analysis. The following is a summary of the analysis. The full screening is contained in a separate technical memorandum.

For the screening analysis, we evaluated systems sized to serve the full build out load of all five neighbourhoods combined (a diversified peak of about 25 MW). Heating loads exhibit high peaks for very short periods. In order to increase economic viability, the alternative energy system is typically sized to 35 – 45% of peak load (8 – 9 MW in this case). At this capacity, the system can supply 70 to 80%+ of the annual load.[10] The remaining capacity and annual energy requirement is typically supplied through natural gas boilers, which have lower capital costs.

The alternative energy sources considered in the screening analysis included the following:

- Sewer heat recovery at pump stations (e.g. Scott Crescent, Victoria Street);
- In-main sewer heat recovery (e.g. Victoria Street sewer main upgrades);
- Ocean loop heat recovery (e.g. Waterfront Lands tidal lagoon, Blind Channel, Squamish Bay);
- Geoexchange included open and closed loop systems (e.g. in City parks);
- Biomass combustion (heating only);[11]
- Biomass gasification with cogeneration; [12]
- Gas-fired combined heat and power (CHP); and
- Local waste heat (e.g., industrial waste heat).

[10] The amount of energy that can be supplied is a function of the system capacity, heating load duration curve (the number of hours each year that demand is above that capacity) and the characteristics of specific technologies (e.g., the ability of technologies to be used when demands on the system are very low such as off-peak periods and summer months).

[11] Biomass gasification could be considered in a heating only application (similar to Dockside Green). However, for the purposes of the screening, we use indicative performance and costing data for conventional biomass combustion technology (with advanced emission controls), which is well established at the scale relevant to this study.

[12] Biomass gasification involves the creation of a biogas (syngas) which can be used in an engine to produce electricity with waste heat recovery for district heating. This technology is not yet considered commercial but this is the most promising biomass cogeneration technology at the scale relevant to this study.

High-efficiency condensing natural gas boilers were also considered to provide a benchmark central system in the screening analysis.

No significant waste heat sources were identified in the analysis. Large commercial uses will generate some low grade waste heat from cooling, but these will be small, their timing is unknown, and they will be dispersed throughout the site. Both geoexchange and ocean heat could potentially provide cooling services although that would be difficult with fully centralized systems and low levels of cooling. However, there may still be ways to integrate a limited cooling service into these systems. This service may in part offset some of the costs of these systems. In the screening analysis we did not consider cooling due to the tremendous uncertainty over its feasibility and cost. However, we consider the possible impact of an additional cooling service in the detailed business analysis of any short-listed options where relevant.

Figure 6 summarizes the potential contribution of each alternative energy source to total heating loads. This chart reflects the target alternative energy capacity, estimated available resource, and specific technology characteristics. For example, sewer is shown to contribute very little because expected flows are small relative to total loads. Similarly geoexchange is limited by available park area and/or groundwater flow in the case of open loop systems. Closed loop ocean systems are limited by the space requirements for heat exchange equipment. The open loop ocean energy concept (whereby water is diverted to an onshore plant and then returned to the ocean afterwards through intake and outfall pipes) is not as limited and can be sized to the full target capacity. However, we believe ocean energy may capture a lower percentage of total annual energy relative to biomass for an equivalent capacity. This is because of the ability to turn down the heat pump required in a large ocean heat recovery system relative to biomass boilers. Both biomass and natural gas cogeneration can provide a high portion of total energy because of good turn down ability. The contribution from biogas cogeneration reflects the lower heating value for biogas and therefore lower total contribution for the same engine capacity.

Figure 6: Potential Contribution of Alternative Energy to Total Heating Loads

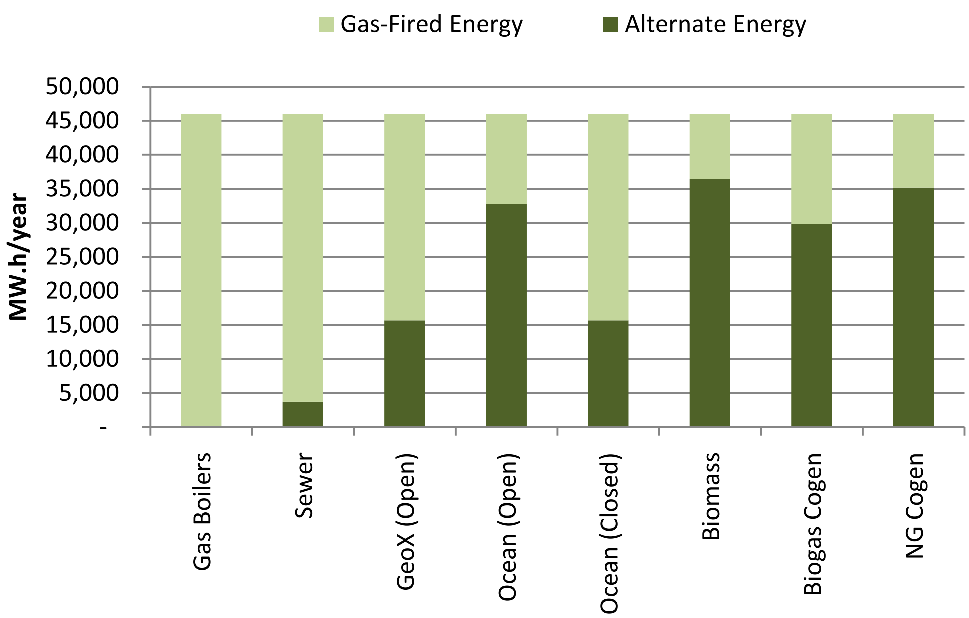


Figure 7 summarizes the real levelized cost (i.e., $2009) of different system alternatives. A levelized cost reflects what would need to be charged over the life of the project to cover both direct operating costs and capital recovery. Capital recovery includes a return on capital (debt interest and/or return on equity). In the screening analysis we assume a discount rate (total return) of 6% real (8% nominal), which is comparable to a private regulated utility Only the direct capital, operating and maintenance costs of each heating option are included are included in the screening analysis. The costs of distribution and other utility overheads are considered in the more detailed business analysis below.

The capital costs are for a complete operating module and generally allow for all equipment, installation, building, electrical, mechanical, engineering, contingency, and PST.[13] Capital costs in the screening analysis do not include land purchase. Land costs are considered in the more detailed business analysis. The capital costing reflects the target or available size of each alternative (whichever is larger) and the costs of natural gas boilers to meet residual peak and annual energy requirements. The levelized cost estimates for screening reflect only heating technologies and exclude the cost of the distribution system, energy transfer stations, land, and other utility overheads, which are considered in the more detailed business analysis below.

[13] Under the proposed HST, district energy systems may be able to claim an input tax credit for PST on capital equipment, reducing capital costs by an equivalent amount.

The accuracy of all capital cost estimates are a function of information known, and can be considered as "indicative" (-15% to +25%). Some costs, notably ocean heat recovery, should be considered "order of magnitude" (-25% to +75%) because of uncertainty in the exact technology and design. The BAU cost is based on the electricity proxy discussed above.

Figure 7: Levelized Cost of Alternative District Energy Technologies

(Including Gas Peaking and Back-up)

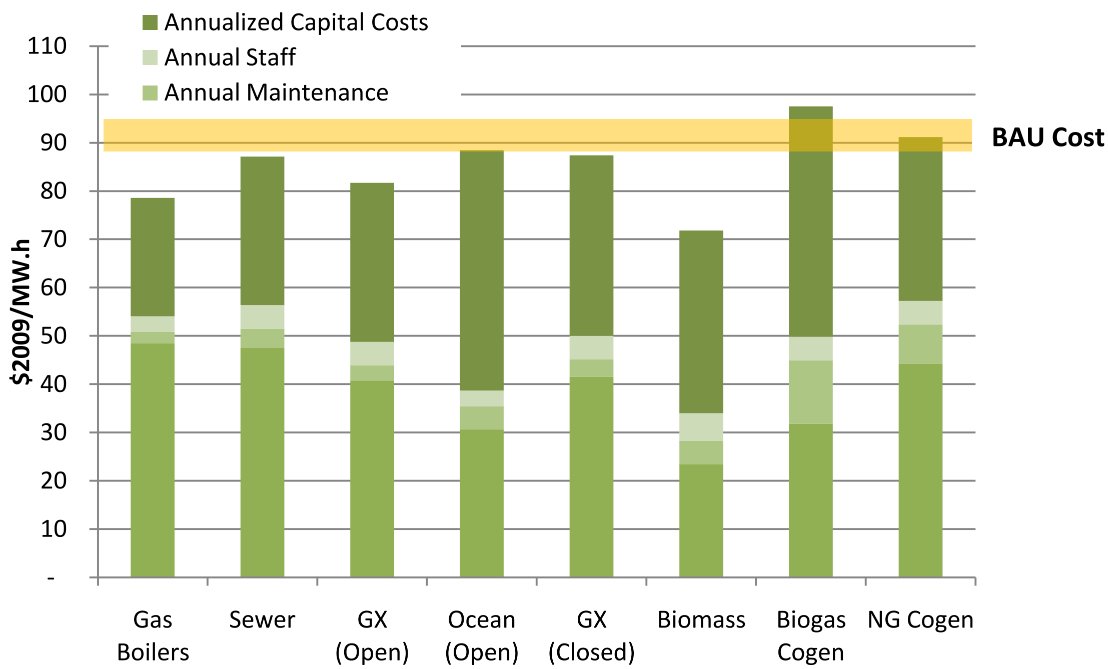
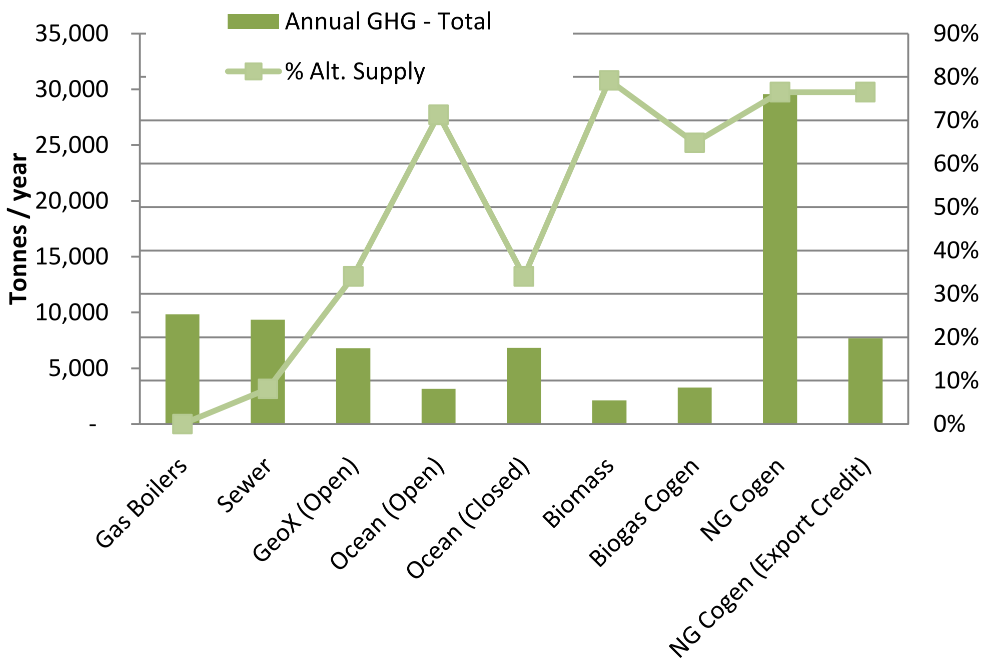


Figure 8 compares the GHG emissions from different systems. The differences in emissions reflect the GHG characteristics of the alternative energy source as well as the amount of natural gas used, which is a function of both available alternative energy supply capacity and operating characteristics. Biomass is considered GHG neutral by most regulatory, policy and public interest advocates. The GHG emission profile of natural gas cogeneration depends upon the perspective used. Natural gas cogeneration increases total emissions in B.C. because other existing and planned electricity sources in B.C. are GHG neutral. However, from a regional perspective (Alberta and the western U.S.) natural gas cogeneration reduces GHG emissions because of the high portion of coal and less efficient natural gas facilities in the region. Most jurisdictions around B.C. are aggressively pursuing natural gas cogeneration but opportunities are limited by the availability of loads that are sufficiently close and large to utilize the waste heat recovered from grid-scale facilities. B.C. has no clear policy with respect to the treatment of GHG emissions from natural gas cogeneration, although natural gas cogeneration is considered clean under the BC Hydro standing offer program.

Figure 8: GHG Emissions of Alternative District Energy Technologies



Some general conclusions from the screening analysis included the following.

- There is insufficient sewer resource compared to total loads. Sewer heat could be combined with other resources. However, there is added complexity associated with integrating multiple heat sources, particularly in the early implementation of a new system. Furthermore, there are other attractive resource options with sufficient capacity to serve loads, at least in the foreseeable future.

- Natural gas cogeneration is a fairly established technology and its performance and capital costs are fairly well known. Natural gas co-generation appears more expensive than some other options. However, the cost-effectiveness of cogeneration is very sensitive to assumptions about the future value of electricity output, which are likely to change in the near future with the results of the clean power call and other government policy. BC Hydro continues to express interest in cogeneration. Natural gas co-generation increases GHG emissions when looking at B.C. electricity only. However, in context of the larger regional electricity system, natural gas co-generation has net GHG benefits. Natural gas cogeneration is also a possible stepping stone to future biogas cogeneration (via gasification of biomass) since a plant can be designed to adopt biogas at some point the future. There are also opportunities to further refine the sizing and staging of natural gas. Given these uncertainties and opportunities, we recommend further investigation of this option.

- Biogas co-generation is less proven (less actual operating history) and still looks more expensive than natural gas cogeneration. However, it could be considered in the future, possibly through a transition strategy from natural gas cogeneration to biogas cogeneration.

- There does not appear to be sufficient open space for closed loop geoexchange (relative to total loads). Open loop geoexchange may be viable. Ocean thermal energy is very similar to geoexchange but may be more applicable to this site given its proximity to the ocean. We believe open loop ocean thermal energy will be more viable and cost effective than closed loop systems. Further optimization of the ocean loop concept may be possible in the detailed design stage. For example, it may be possible to use the ocean loop concept for limited cooling within the site, providing some capital offset to apply to the project.

- Biomass is one of the lowest cost options in the screening analysis and offers one of the greatest reductions in GHG emission as well as electricity consumption. Biomass is an abundant local resource and one with considerable history in Squamish.

Following a presentation of the screening results to the study sponsors, a decision was made to take biomass (heating only), ocean thermal, and natural gas cogeneration into the more detailed business analysis. These are three very different approaches to providing district energy and each has different pros and cons that should be explored further.

7.0 Business Analysis

7.1 Introduction

The purpose of the more detailed business analysis is to determine the basic viability and best direction for a district energy system in order to move this initiative forward to next stages. These would include:

- Establishing a municipal policy framework to facilitate / promote district energy,
- Establishing an ownership and development strategy, and
- Undertaking detailed design work.

The business analysis involves a more detailed staging of loads and capital than the simple screening. We also consider different load and technology scenarios in order to inform decisions about the scope and approach to district energy. However, the business analysis is not a detailed system design. It is a framework to establish a general direction and to provide a placeholder for potential capital requirements. Further optimization of the system will be required in the detailed design phase that follows a decision of whether and how to proceed with district energy.

District energy should not be seen as a one-off engineering project, but as an ongoing business. We consider defined service areas and basic technology configurations in this analysis in order to establish viability. Once a decision to proceed is made, the system concept and service area should continue to be refined in the detailed design and implementation phases.

7.2 Scope of Service

Consistent with the insights gained in the screening phase, the business analysis focuses on district heating. Centralized cooling service was ruled out because expected cooling loads are small and dispersed. However, if Ocean Heat is pursued, there may be some opportunity to offset system costs through the integration of commercial cooling loads. This would need to be a consideration in the detailed design phase. Given uncertainty in cooling needs and locations, at this stage we use sensitivity analysis to test the possible effect of a cooling service on the relative performance of Ocean Heat.

The business analysis focuses on Area A as the system core (about 20% of potential system demand concentrated largely along the waterfront). We also considered incremental extensions to Oceanfront and/or Waterfront. Both of these are large new developments on either side of Area A and complete build out is expected to take somewhat longer than Area A. Areas C and D represent a much smaller portion of total potential loads and redevelopment of these neighbourhoods will likely be more dispersed. We therefore excluded them from consideration in this business analysis. However, integration of specific loads in these neighbourhoods should be considered during design and implementation phases.

There is also about 85,000 m2 of existing building area within the five neighbourhoods. However, much of this space is likely to be redeveloped in the next 30 years. We therefore do not consider potential retrofits in the business analysis, which have a very different business case. However, we would expect some consideration of retrofits in the design stage once a decision is made to proceed.

7.3 Load Phasing

For the purposes of the business case, we worked with District planners to develop geographic phasing scenarios for each of the three target service areas. In each case, loads are grouped into four phases of approximately five years each. These phases are used to stage distribution and energy centre capital. The phasing assumptions are summarized in Table 11 and Figure 9. Figure 10 shows the approximate geographic phasing of individual neighbourhoods used to develop capital cost estimates and phasing.

Table 11: Detailed Load Phasing for Business Analysis

		Phase 1	Phase 2	Phase 3	Phase 4
Area A					
Heated Floorspace	m2	22,600	90,300	101,600	111,700
Annual Heating Demand	MWh	1,500	6,200	6,900	7,600
Peak Heating Demand	MW	0.9	3.6	4.1	4.5
Oceanfront					
Heated Floorspace	m2	10,900	36,300	127,100	236,000
Annual Heating Demand	MWh	800	2,700	9,400	17,400
Peak Heating Demand	MW	0.5	1.5	5.4	9.9
Waterfront					
Heated Floorspace	m2	4,700	31,000	77,600	139,700
Annual Heating Demand	MWh	400	2,500	6,400	11,400
Peak Heating Demand	MW	0.2	1.2	3.1	5.6

Figure 9: Annual Energy Demand by Year

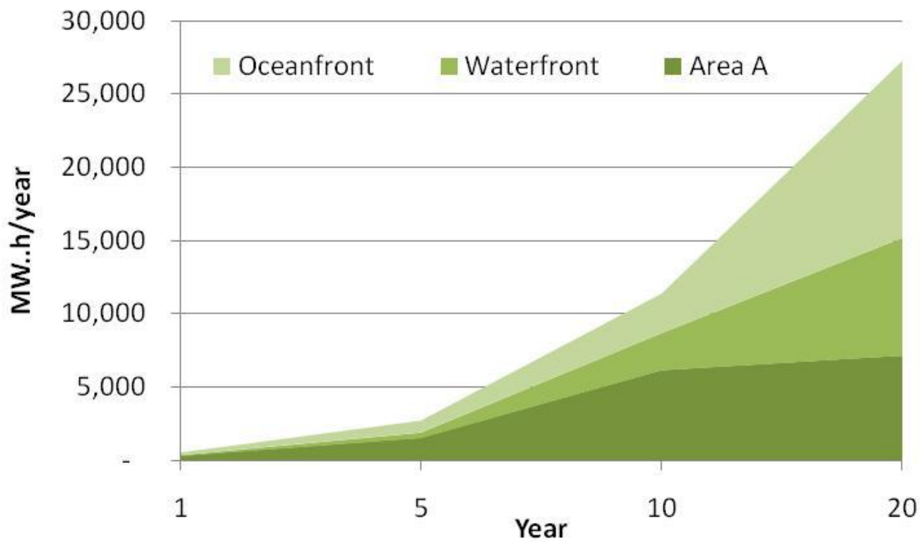
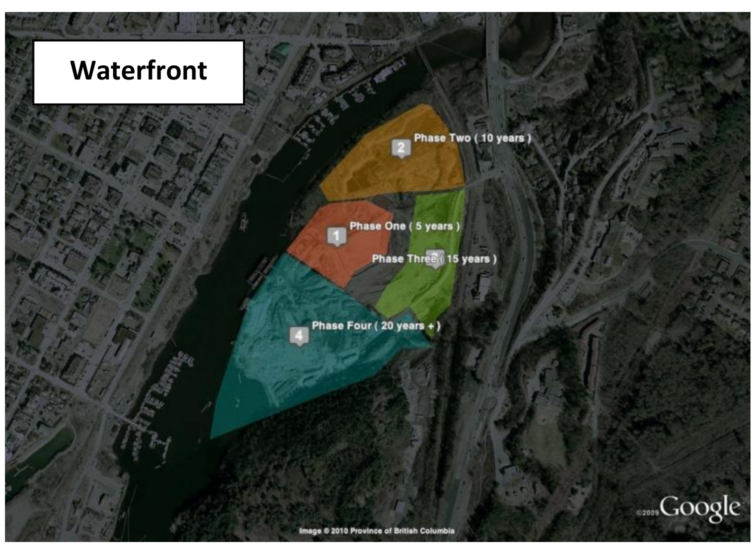


Figure 10: Geographic Phasing Assumptions by Neighbourhood



7.4 Supply Technologies

Following the screening analysis and discussions with Council and other study sponsors, we decided to proceed with a more detailed phasing study of three technologies:

- Co-generation (natural gas with potential long-term transition to biogas);
- Biomass (heating only); and
- Ocean heat (open loop).

All of these systems would be sized to about 35% of peak diversified loads. At this size, 65 – 80%+ of the annual load would be supplied by the alternative technologies. Natural gas boilers would be used for peaking and back-up. Table 12 summarizes the approximate sizing and timing of alternative energy capacity under each demand scenario. In the case of the larger demand scenarios the alternative energy capacity would likely be implemented in two increments.

Table 12: Alternative Energy Capacity Sizing and Timing by Demand Scenario

Demand Scenario	Alternative Energy Capacity	Timing of Alternative Energy Capacity
Area A Only	1.6 MW	~2020
Area A + Waterfront	3.2 MW	~2020 and 2025
Area + Oceanfront	4.7 MW	~2020 and 2025
Area A + Waterfront + Oceanfront	6.3 MW	~2020 and 2025

In order to optimize the alternative energy investment, it is generally more cost-effective to install the boiler capacity first. Once loads reach a sufficient threshold, the alternative energy supply may be installed and the boilers revert to peaking and back-up supply. In the case of the Squamish demand scenarios, the alternative energy systems would be installed around 2020. This timing could be advanced if load develops more quickly, costs can be reduced through design and tendering process, or additional grants are received.

This approach to staging investment minimizes the costs and risks associated with installing energy sources with high capital costs in advance of loads. Boilers are also easier to install in smaller increments. Most alternative energy sources exhibit economies of scale and would be better to install in larger lumps. For example, the ocean heat alternative will require ocean intake and outfall pipes running to and from the energy centre. These are best installed when they will see high levels of utilization.

In addition to deferring the alternative energy system, we also believe that in the first few years it would be better to rely on temporary boilers to meet individual loads. Investment in distribution capital can then be deferred until there are more loads and/or until installation can be coordinated with the installation of other municipal infrastructure.

Any attempt to advance installation of distribution assets, the permanent energy plant or alternative energy would increase levelized costs for each demand scenario relative to those calculated in this analysis. Additional grants or other savings (e.g., from coordinated installation of infrastructure) would be required to offset these higher costs.

The heat source screening technical memorandum contains more detailed information on each supply technology. Key features of each of the short-listed options are summarized below. Attachment A summarizes the detailed assumptions about capital phasing under each demand scenario.

7.4.1 Ocean Heat

Ocean heat involves extracting heat energy from ocean water via a heat exchanger and heat pump. For the purposes of the business analysis we used an "On-shore" concept, drawing water from Mamquam Channel (adjacent to core service area).

We believe an on-shore system is more applicable to this scale of heat recovery. The on-shore concept requires less ocean area and results in fewer potential conflicts with other uses (e.g., recreational boating, which may damage in-ocean heat exchangers). On-shore systems also allow better access to equipment for maintenance and safety.

A key challenge of ocean heat recovery is dealing with organisms, silt and sediment. The capital cost estimate for the ocean heat alternative includes allowances for intake screens and large filters. Intake options would need to be considered in more detailed design stage but could include a fixed intake structure on the foreshore (e.g., underneath walkway or observation pier) or some kind of floating structure. It may be necessary to use large diameter intakes or multiple intakes to minimize flow velocities.

Costs for this alternative includes ~400 metres of 400 mm piping to connect intakes and outfalls to a heat exchanger / heat pump system located at the proposed Energy Centre (see below).

Permitting issues could be significant. A separate report by Hemmera provides an overview of permitting issues.

Ocean heat will require ongoing use of electric heat pump to raise temperatures to useful levels. There is some uncertainty over the coefficient of performance for large heat pumps in a specific application/. Ocean heat system could also be used to supply some cooling service to commercial loads but this would require validation in a detailed phase. We considered the impact of adding cooling loads in the sensitivity analyses below.

7.4.2 Natural Gas Cogeneration

For the scale of application proposed here, we recommend reciprocating natural gas fired engines for co-generation. Similar concepts have been implemented in Markham, Sudbury, Cornwall, and Hamilton. Jenbacher JMS620 engines were used in the cost analysis. Three units were assumed in the largest demand scenario (Area A + Oceanfront + Waterfront).

Electricity from cogeneration would be sold under BC Hydro's Standing Offer. The Standing Offer requires an overall efficiency (heat and electricity recovery) of ~80% on an annual basis. To achieve a minimum 80% fuel efficiency at this scale, heat extraction will need to be optimized carefully, including from lube oil systems, jacket water, and from the flue gas stream. Due to low summer baseloads, particularly at night, often cogenerators will cycle off during this period. For this reason, we expect ~4,500 – 5,500 run hours to optimize total system efficiency and maximize Standing Offer price (which is weighted by time period).

Ideally, engines and other components would be selected that are capable of a future fuel switch to biogas. A separate biomass gasification system could then be added to the facility at a future date.

7.4.3 Biomass Heating

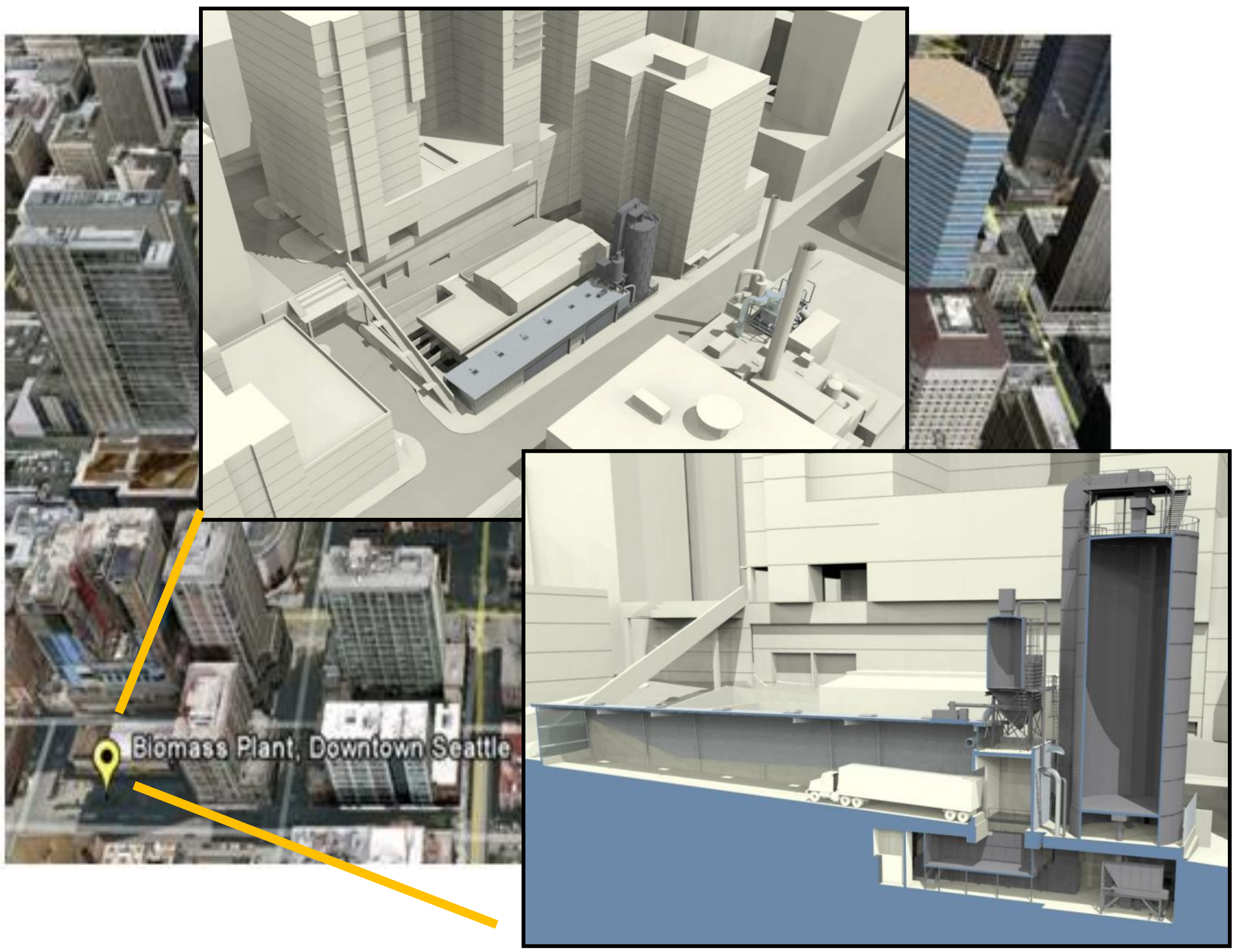
Biomass district heating plants are very common in Scandinavia, some utilizing wood pellets manufactured in B.C. In Canada, biomass plants have recently been implemented in Revelstoke BC (2005), Oujebougamou QC (1994), Charlottetown PEI (1986), and Dockside Green in Victoria (2009). A very large scale biomass system is operating in downtown St. Paul, Minnesota (2001) and an existing district steam plant in downtown Seattle, Washington has recently been retrofitted to incorporate a large biomass boiler (Figure 11).

Conventional biomass combustion technologies are well established and proven. Non-conventional approaches such as biomass gasification (Nexterra technology) are also gaining interest, although we believe these systems will make most commercial sense in the context of a cogeneration facility where the biogas can be used in a reciprocating engine. Dockside Green uses gasification for heating only and another gasification plant has recently been installed at a paper mill in New Westminster. UBC has recently announced a small scale pilot gasification project involving co-generation.

Fuel for a biomass plant would be processed offsite to boiler "spec" grade and delivered in covered truck trailers to minimize visual impacts (and dust). On-site storage would need to be sufficient to meet about three peak demand days. At full build out a plant to serve all three target areas would require up to five truck deliveries (~20 tonnes) per day during the peak heating period.

Preliminary costing in the business analysis is based on existing combustion technology (with advanced emission controls), which has a long track record and many equipment suppliers. Costs include allowance for emissions cleanup equipment to meet limits for particulate matter (assumed < 15 mg/nm3). Other technology approaches could be considered in the detailed design and vendor selection stage.

Figure 11: Seattle Steam Biomass Plant



One of the biggest challenges for biomass is the cost and security of biomass fuel supply. If Squamish decides to proceed with a biomass system, further analysis of biomass fuel supply will be required.

All wood waste currently sent to landfill in Squamish is sorted and diverted from the landfill. A total of 624,570 kg were diverted in 2009 and sent to the Whistler compost facility, representing about 3.3% of total waste sent to the Landfill. However, there are many sources of wood waste outside the municipal waste stream.

Agriculture and Agri-Food Canada has developed a tool (BIMAT) for estimating the amount of biomass available in an area. This tool suggests there are over 22,000 oven dry tonnes of wood waste available within 10 km of Squamish, which is equivalent to over 44,000 wet tonnes assuming 50% moisture content. For comparison, about 11,500 wet tonnes would be required to supply a system serving Area A, Waterfront and Oceanfront at build out.

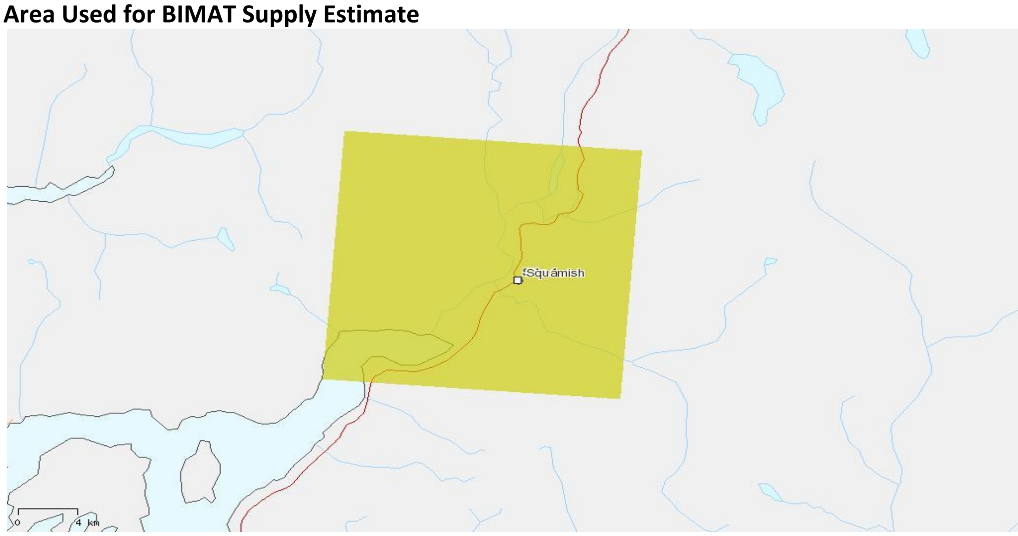
Biomass required at build out for each service sub-area

Area A	13%	2,318	wet tonnes required
Oceanfront	33%	5,727	wet tonnes required
Waterfront	20%	3,507	wet tonnes required
	Total	11,553	wet tonnes required

BIMAT estimate of supplies within 10 km of Squamish

Urban wood waste	5,728	oven dried tonnes
Softwood roadside harvest	13,803	oven dried tonnes
Hardwood roadside harvest	2,557	oven dried tonnes
	22,088	oven dried tonnes
	44,176	equivalent wet tonnes (50% moisture)

Area Used for BIMAT Supply Estimate



Some of this waste is already spoken for. For example, the District of Squamish currently delivers most of its green waste to Triack resources. Triack supplies ~25,000 wet tonnes to Howe Sound Pulp and Paper, and handles some other volumes. Triack has indicated it is currently operating at only ~50% capacity. Triack suggests there are no long term constraints on material supply and is currently investigating with the Ministry of Forests the recovery of residue from local forestry operations.

Biomass from private sources in the region continues to be disposed of via open burning. For example, five thousand cubic metres were disposed of at Watts Point via open burning last year alone. District energy offers an opportunity to put this waste to a productive local use and reduce local air emissions from open air burning.

Figure 12: Open Air Burning of Wood Waste at Watts Point Log Sort

March 8, 2010. Photo Courtesy of Eric Anderson.

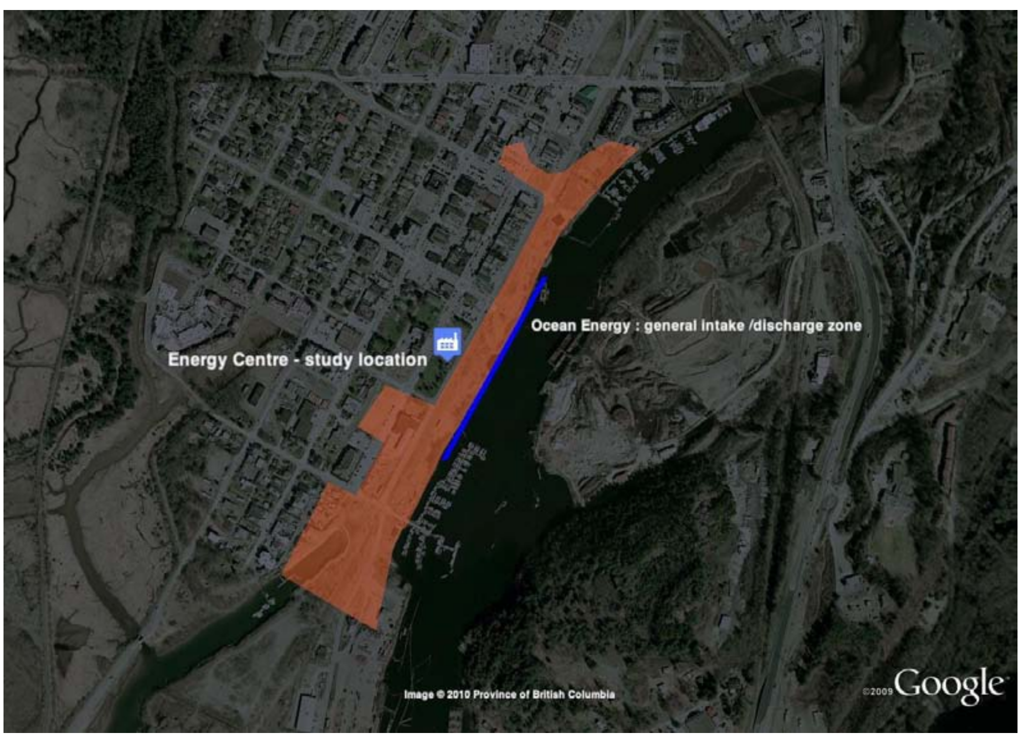
7.5 Energy Centre Locations

As noted above, we recommend the use of temporary boiler plants for the first few years of the system to help optimize capital expenditures. Eventually a permanent energy centre will be required. The location of the energy centre will determine in part the layout and sizing of distribution piping system. For the purposes of the business analysis we assumed a single energy centre and selected a representative central location within Area A at Block 19 (Figure 13), which is a good location from the perspective of phasing and future expansion (as well as access to the ocean for the ocean heat source). Block 19 is a District-owned parcel that currently contains a park and parkade. It is nearly 7,000 m2 in size and the energy centre could take up to 2,000 m2 depending upon the technology.

The exact location of the energy centre would need to be refined in the detailed design phase and would need to be informed by the desired future technologies. Multiple plants could also be considered, although a single plant would have better economies of scale. These can be considered as future potential optimizations around the basic business case presented here.

Figure 14 provides some examples of energy centre designs. Some of these are biomass-based systems. Footprints will vary somewhat across technologies. Regardless of the specific technology, all energy centres would need to have stacks for the natural gas peaking and back-up system. Energy centres can be designed with architectural sensitivity and may be integrated with other uses (e.g., Hamilton's energy centre is attached to a high school). For the purposes of the business analysis, we have assumed a utility grade building. Additional architectural features would add to the baseline costs here.

Figure 13: Representative Energy Centre Location



Note: Block 19 was selected as a possible energy centre location for the creation of a preliminary business case. Other sites may be considered within the detailed design phase. Possible locations for intakes and outfalls for ocean heat are also shown.

Figure 14: Sample Energy Centres

The approximate footprints of the energy centre required for each demand and supply scenario are summarized in Table 13.

Table 13: Footprint of Energy Centre by Demand and Supply Scenario (m2)

Demand Scenario	Biomass	Ocean Heat	Cogen
Area A Only	470	450	490
Area A + Waterfront	790	730	800
Area A + Oceanfront	1,020	1,020	1,000
Area A + Waterfront + Oceanfront	1,320	1,290	1,310

7.6 Evaluation Method

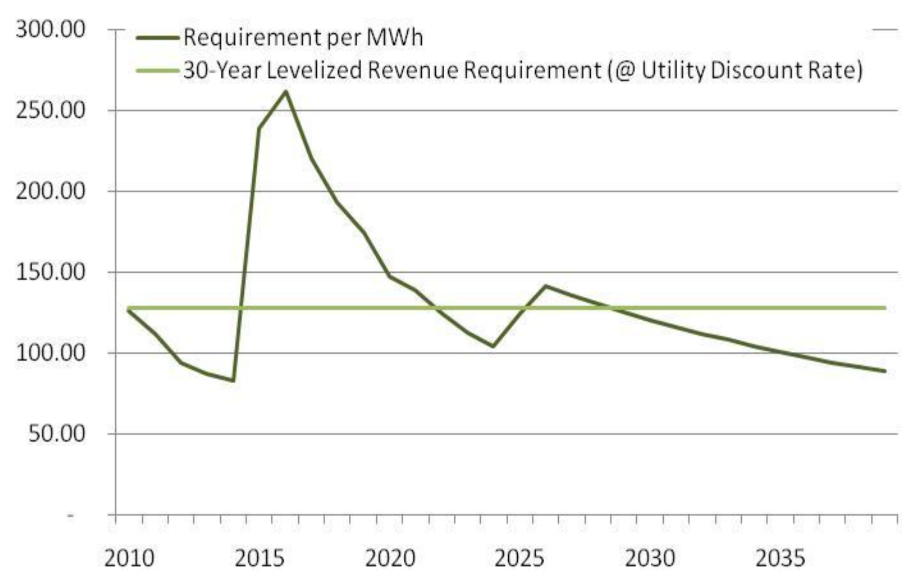
There are many ways to evaluate and characterize viability. One approach is to estimate a return under different scenarios. This approach requires a specific assumption about revenues as an input to the business analysis. For the purposes of this study, we chose to evaluate the levelized cost of energy for each scenario and compare that with the levelized cost of electric heat (our benchmark for customer avoided costs). Levelized costs are commonly used by BC Hydro to evaluate and compare resource alternatives. A levelized cost reflects the price that would need to be charged by the NEU over some established time period (in this case we use 30 years) to recover all capital and operating costs for the utility, including a target return on capital. A common rate of return (discount rate) is used across all alternatives, as explained further below.

Where levelized costs are lower than our benchmark, there may be opportunities for additional customer savings or investor returns over and above the benchmarks. Where levelized costs are above the benchmark, there must be some willingness to impose a further premium on customers (to account for intangible benefits) and/or grants or other refinements to the business model to reduce costs.

Levelized costs are derived from a pro forma for each demand and supply scenario which includes all utility operating and financing costs. The pro forma calculates the annual operating and capital costs of the utility and divides these by heat sales. This "revenue requirement" will vary by year depending upon both sales and the timing of capital additions. The levelized cost or revenue requirement is a constant value that gives an equivalent amount of revenues on a present value basis.

In addition to the supply technologies themselves, the business analysis includes the estimated costs of distribution and energy transfer stations, as well as other utility overhead costs such as insurance and property taxes. Detailed input assumptions are described further below.

Figure 15: Example of a Levelized Revenue Requirement



Payback vs. Return Metrics

A simple payback indicates the timeframe required to recover the upfront installation costs of a project based on savings or net operating cashflows (i.e., excluding financing and depreciation costs). A simple payback is useful for screening for simple projects with a common lifespan. But payback is not a measure of profitability, particularly when comparing projects with different lifespans or projects involving capital outlays over time. Simple payback also does not reflect the time value of money (i.e., carrying costs of capital).

Return is a true measure of the profitability. Return can be measured in several ways. A target return (discount rate) can be utilized to estimate a net present value of all cashflows (including capital) over the life of a project and if the net present value is greater than zero then the project is considered profitable (relative to the investor's cost of capital). Alternatively, the internal rate of return (IRR) or total return on investment (ROI) for a series of cashflows can be estimated and then compared to the cost of capital. If financing is excluded from cashflows (i.e., capital costs are incurred as spent) then the results is an "unlevered" IRR or ROI. This can be compared to the weighted average cost of capital of the investor, which reflects the relative mix of debt and equity and their respective costs that would be used to finance the investment. Alternatively, debt financing and depreciation could be used in the cashflows instead of direct capital costs and a residual return on equity (ROE) could then be calculated on the investment.

In the Squamish analysis, we compare a levelized rate to the customer business as usual cost to determine viability (or grant requirements). The levelized rate calculations reflect a target return over the project life. We use two representative scenarios to calculate levelized rates: a) a conventional municipal financing model with 100% debt and no property or income taxes; and b) a conventional regulated private utility financing model with a 60/40 debt to equity ratio, a regulated return on equity, and property taxes (which would not be incurred in conventional on-site systems). Income taxes are not considered because they are more complex to calculate at this stage of analysis and based on analyses for other projects they have a limited effect on levelized rates (2 – 5%) for a new NEU because of the accelerated capital cost allowances and net operating losses in early years.

7.7 Detailed Financial Assumptions

All cashflows are estimated in real $2010 dollars (i.e., before inflation) for simplicity. Total project capital costs include a contingency but exclude PST (given expected rebate under HST). Detailed capital phasing assumptions are summarized in Attachment B.

Table 14: Total Capital Costs by Demand Scenario and Energy Source ($2010 thousands)

Demand Scenario	Biomass	Ocean Heat	Cogen
Area A Only	8,400	9,800	10,600
Area A + Waterfront	17,300	19,700	21,400
Area A + Oceanfront	20,300	25,400	26,000
Area A + Waterfront + Oceanfront	29,200	34,900	36,800

For the base case analysis we assume a private utility with a regulated capital structure and rate of return similar to Dockside Green. The regulated capital structure is 60% debt and 40% equity. The regulated return on equity is 10% (8% real), about 100 basis points above the comparable benchmark low risk utility. We assume a private debt rate of 6%. The resulting weighted average cost of capital is 7.6% (5.6% real). In the sensitivity analyses we also consider a municipal financing model based on 100% debt at a comparable long-term debt rate.

Other key assumptions in the pro forma analysis are as follows.

Depreciation rates (consistent with other studies and BCUC filings)

- Energy Centre Building - 1.50% /year
- Energy Centre Equipment - 3.00% /year
- DPS - 1.50% /year
- ETS - 3.00%/year

Equipment maintenance

- 0.5 – 0.75% of capital cost

Distribution energy losses

- ~3% of energy demand

Corporate overheads

- 2.5% of utility operating costs

Staffing costs (with overheads)

- Administration - $110 k / year
- Operators - $85k / year

Liability and property insurance

- 0.2% of capital costs / year

Property taxes

- On-site systems are not subject to property taxes.
- There is uncertainty over property tax treatment of the NEU (few precedents). Key issues are the assessed values and form of levy.

- Municipal infrastructure is tax exempt, although Vancouver has chosen to include property taxes in rates for the SEFC NEU when doing so would not exceed the target rate cap. This was intended to provide flexibility for future divestment of assets and to ensure equity between NEU ratepayers and city-wide taxpayers.
- In the business analysis we assume a private utility. We assume a rate of 2% on the value of energy centre land and building (based on current mill rates), and 3% of gross revenues as a proxy for distribution asset property taxes (equivalent to the franchise fee normally paid by Terasen).

Sales taxes

- GST, PST and HST taxes are not included in NEU rates because of exemptions or because they apply to both the BAU and NEU cases.
- No sales tax on NEU fuel purchases assumed because of recent provincial exemption.

Income taxes

- Income taxes are excluded because of the complexity of income tax calculations at this stage of analysis.
- Under a levelized rate structure and with accelerated capital cost allowances, there would be no income taxes payable in early years of project.
- Based on more detailed analyses on other projects, income taxes could increase levelized revenue requirement 3 – 4% over 30 years under a private ownership model.

7.8 Base Case Results

Base case levelized costs for different demand and supply scenarios are summarized in Figure 16. Table 15 provides a detailed breakdown of the individual cost items in the levelized cost calculations for the Area A + Waterfront + Oceanfront development scenario. Impacts on GHG emissions (compared to BAU) and natural gas and electricity consumption are summarized in Table 16 and Table 17. Table 18 provides a summary of the pro forma outputs.

Under base case assumptions, all options are more costly then the BAU. However, the base case represents a conservative scenario with private financing, property taxes, and no grants. There may also be opportunities to further optimize the selection and staging of equipment in the detailed design phase.

All options exhibit economies of scale, so levelized cost declines as the final system size increases. This is partly due to economies of scale in capital equipment and lower unit staffing costs with larger scales. Securing a large service area will be critical to success.

Biomass is the least cost option in all demand scenarios and has the highest total GHG emission reductions and greatest reliance on local resources. As shown further in the sensitivity analyses below, the larger biomass system starts to approach BAU costs, under a more traditional municipal financing model that also excludes property taxes, even before taking into account grants.

Biomass and ocean heat will result in lower natural gas and electricity consumption at build out relative to the BAU. Natural gas cogeneration would increase natural gas use (unless natural gas is substituted with biogas) but would also produce a local source of electricity.

Figure 16: Base Case Levelized Cost Outputs, No Grants ($2010 / MW.h)

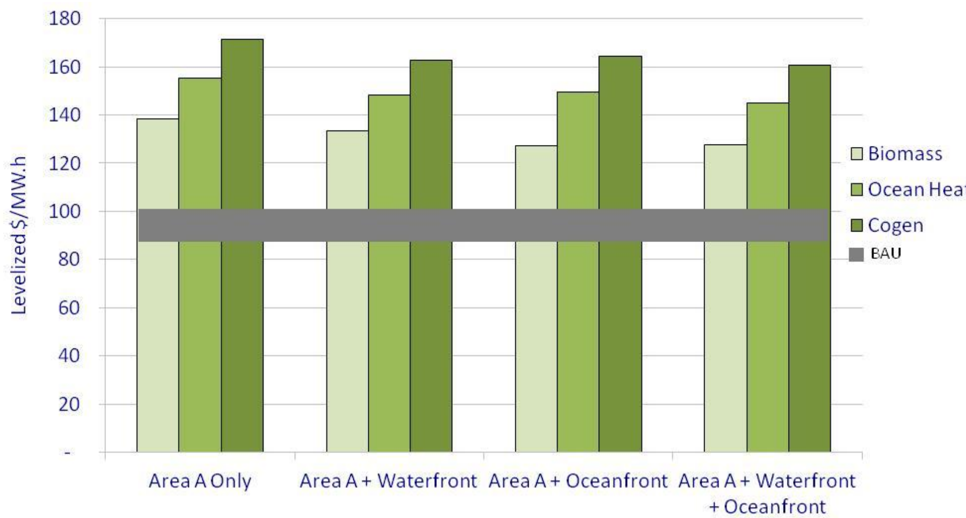


Table 15: Detailed Levelized Cost Components ($2010/MW.h)
(Area A + Waterfront + Oceanfront Development Scenario)

Component	Biomass	Ocean Heat	Cogeneration
Staffing	10	12	13
Property Taxes	8	8	9
Fuel	25	34	76
Other Operating Costs	17	15	31
Depreciation	22	26	27
Interest	19	21	22
ROE	27	30	32
Total	128	145	211
Electricity Credit	-	-	50
Total After Electricity Credit	128	145	161

Table 16: GHG Emission Outputs

Demand Scenario	Biomass	Ocean Heat	Cogen (BC Perspective)	Cogen (Regional Perspective)
		tonnes / year change at build out		
Area A Only	(1,300)	(1,100)	1,100	(900)
Area A + Waterfront	(3,000)	(2,200)	3,700	(1,800)
Area A + Oceanfront	(5,000)	(4,100)	3,700	(3,500)
Area A + Waterfront + Oceanfront	(6,600)	(5,200)	6,100	(4,300)
		% change at build out		
Area A Only	(74%)	(62%)	62%	(51%)
Area A + Waterfront	(79%)	(58%)	97%	(47%)
Area A + Oceanfront	(81%)	(67%)	60%	(57%)
Area A + Waterfront + Oceanfront	(80%)	(63%)	74%	(52%)

Table 17: Impacts on Gas and Electricity

Demand Scenario	Biomass Scenario	Ocean Heat Scenario	NG Cogen Scenario
Area A Only	MW.h	MW.h	MW.h
Incremental gas increase (reduction)	(7,200)	(6,200)	7,100
Incremental electricity increase (reduction)	(1,800)	(100)	(1,800)
Additional electricity production	-	-	5,100
Area A + Waterfront			
Incremental gas increase (reduction)	(15,800)	(12,200)	22,700
Incremental electricity increase (reduction)	(5,300)	(1,000)	(5,300)
Additional electricity production	-	-	14,100
Area A + Oceanfront			
Incremental gas increase (reduction)	(27,200)	(22,500)	23,500
Incremental electricity increase (reduction)	(5,600)	-	(5,600)
Additional electricity production	-	-	18,500
Area A + Waterfront + Oceanfront			
Incremental gas increase (reduction)	(35,300)	(28,500)	38,400
Incremental electricity increase (reduction)	(9,200)	(1,000)	(9,200)
Additional electricity production	-	-	26,900

Table 18: Sample Pro Forma Outputs (Area A + Oceanfront + Waterfront)

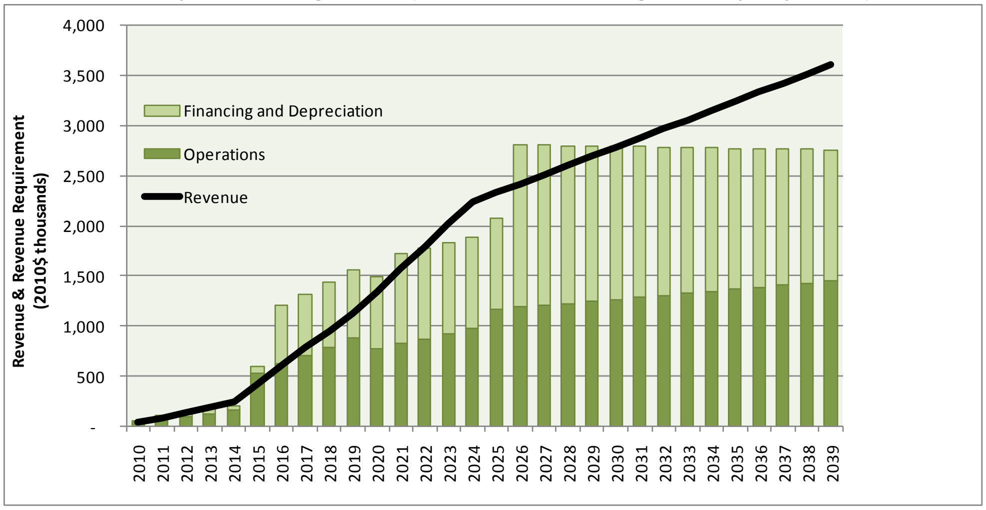
	2010	2015	2020	2025
Heat Sales (MW.h)	546	4,462	13,652	23,602
Biomass Supply Scenario				
Cumulative Capital Costs (Before Grants) ($,000)	487	11,265	16,925	28,771
Annual Operating Costs (Before Financing)	53	673	928	1,374
Annual Net Revenue (Before Financing)	(12)	(249)	421	957
GHG Emission Increases / (Reductions)	20	28	(2,431)	(4,240)
Ocean Heat Supply Scenario				
Cumulative Capital Costs (Before Grants) ($,000)	487	10,527	18,079	34,407
Annual Operating Costs (Before Financing)	52	663	1,034	1,640
Annual Net Revenue (Before Financing)	(11)	(240)	314	691
GHG Emission Increases / (Reductions)	20	28	(1,756)	(3,328)
Cogen Supply Scenario				
Electricity Sales (MW.h)	-	-	9,154	17,409
Electricity Revenues ($,000)	-	-	825	1,493
Cumulative Capital Costs (Before Grants) ($,000)	487	11,103	20,350	36,316
Annual Operating Costs (Before Financing)	88	797	1,966	3,387
Annual Net Revenue (Before Financing)	(47)	(373)	207	437
GHG Emission Increases / (Reductions)	20	28	2,103	3,960

The charts below show an example of annual revenues compared with annual revenue requirements over 30 years for each of the representative private (base case) and municipal financing scenarios. These charts show the full demand scenario (Area A, Waterfront and Oceanfront) and biomass supply case, which is currently the least cost supply scenario. The revenue is based on floor area and electricity prices + a 10% premium. The revenue requirement includes all financing costs and also the grant required to achieve a competitive price for end users. The magnitude of grant required is higher for a private financing model. The grant requirement is about 5-10% of total capital for a municipal finance model and 30 – 35% of total capital for a private finance model with property taxes.

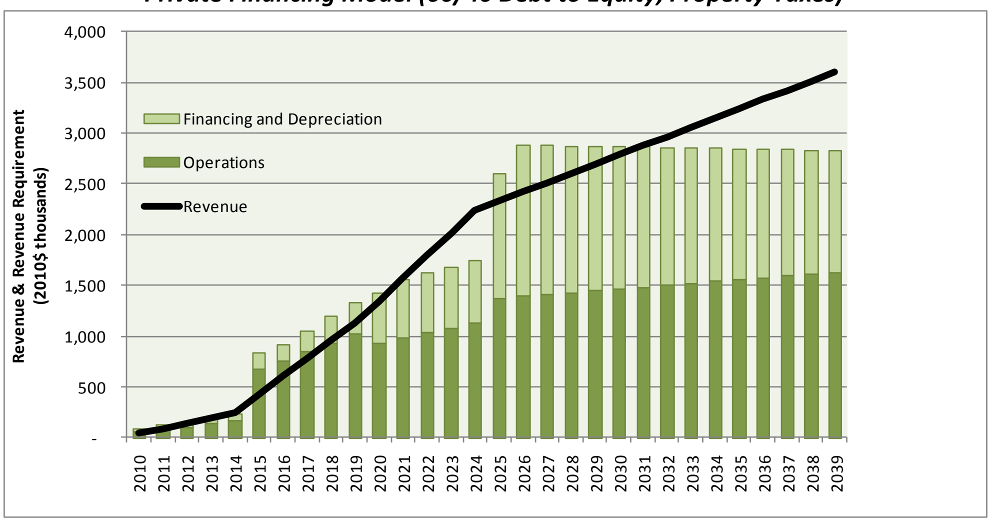
The actual capital requirements by year are also shown below the charts. As shown, the utility is roughly break even in early years before the distribution system and permanent energy centre is constructed. After 2015, the utility would have years of deficits (when revenue requirements exceed revenues) and surpluses. Over the project lifecycle, the utility would achieve the target return under the assumptions used for each scenario.

Figure 17: Annual Revenues, Revenue Requirements (After Grants) and Capital Expenditures

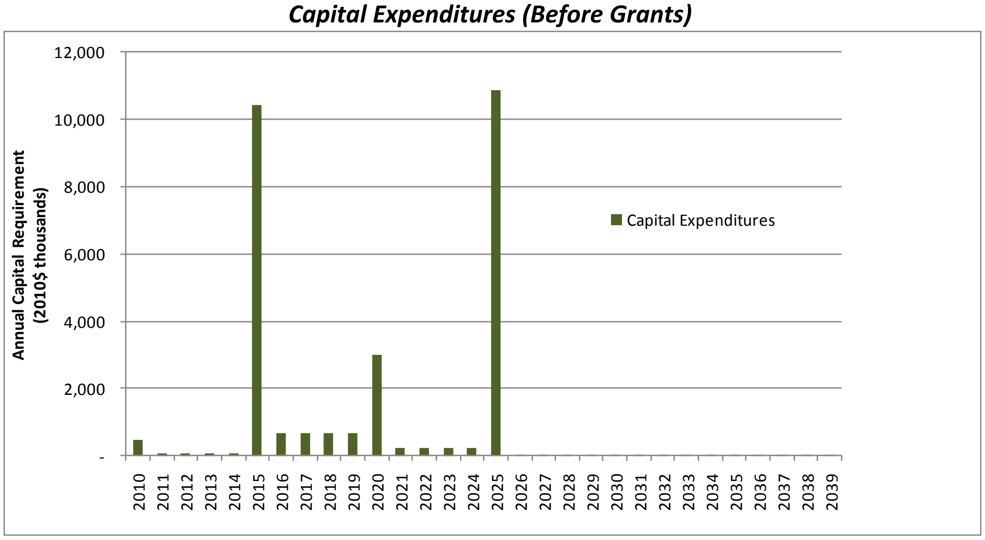
Municipal Financing Model (100% Debt Financing, No Property Taxes)



Private Financing Model (60/40 Debt to Equity, Property Taxes)



Capital Expenditures (Before Grants)



District Energy and Property Taxes

Municipally-owned utilities are exempt from property taxes. We have included an allowance for property taxes under the private ownership model. Property taxes on district energy are difficult to estimate because there are currently few precedents. There are two key components of district energy systems that may attract property taxes: 1) the Energy Centre; and 2) the distribution system. According to the BC Assessment Authority, the Energy Centre would likely be classified as “Business and Other.” The distribution system would be classified as “Utility”. For the Energy Centre, property taxes would normally reflect the land and building value, but exclude removable equipment (e.g., boilers, heat pumps, etc.). For the distribution system, property taxes would be assessed on the asset value. How exactly that will be established by the Assessment Authority is still uncertain.

The mill rates for each classification are specific to the municipality and these include municipal, regional district, school and the provincial portion of property taxes. Some utilities pay a grant or franchise fee in lieu of property taxes. For the Squamish analysis, we have assumed property of 2% of the Energy Centre Value per year and 3% of gross revenues as a franchise fee in lieu of property taxes. These are simply placeholders.

As shown in this study, property taxes can have a significant impact on revenue requirements and competitiveness or returns for the NEU. It is important to note that systems serving individual buildings would not normally be subject to property taxes. Thus, property taxes on the NEU represent an additional cost for the NEU, which must compete with stand-alone systems that do not attract property taxes. Similarly, any property taxes paid by a district energy system would be a new source of revenues to the municipality that it would not have seen with on-site systems. If the pro forma can accommodate property taxes without jeopardizing cost-effectiveness of the new NEU to end users, then there is a win-win. But where property taxes would result in rates that exceed benchmarks or lower returns below those required by a private utility, they can be a barrier to viability.

Lonsdale Energy Corporation currently does not pay property taxes. The NEU being developed for the Whistler Village will be exempt from property taxes since the Resort Municipality of Whistler retains ownership. The NEU implemented by the City of Vancouver for Southeast False Creek will not formally pay property taxes, but the City has included an allowance of property taxes in the rates, subject to the NEU maintaining competitive rates (i.e., within 10% of electricity). Dockside Green Enterprises in Victoria applied to the Province for a full tax exemption (i.e. to be exempt from assessment by the BC Assessment Authority), with support from Victoria City Council, based on the green benefits of the utility. At the time of the request, the Province was in the process of updating the Community Charter to enable municipalities to establish Revitalization Tax Exemption programs. Due to the imminent legislation, the Province recommended the City of Victoria develop the revitalization program instead.

Revitalization Tax Exemptions

Below is an excerpt from a Ministry of Community Services' primer on Revitalization Tax Exemptions[1]:

> *Section 226 of the Community Charter provides authority to exempt property from municipal property value taxes. To use this authority, a Council must establish a revitalization program (with defined reasons for and objectives of the program), enter into agreements with property owners, and then exempt their property from taxation once all specified conditions of the program and the agreement have been met. Exemptions may apply to the value of land or improvements, or both. Councils are free to specify, within their revitalization programs, the amounts and extent of tax exemptions available.*
>
> *Revitalization tax exemptions are limited to municipal property value taxes (Section 197(1)(a) of the Community Charter only) and do not extend to school and other property taxes, such as parcel taxes. An exemption may be granted for up to 10 years.*

Establishing a revitalization program enables a municipality to waive the municipal portion of the taxes. Despite the reference to tax exemptions only applying to municipal taxes and not school and other taxes, section 131.1 of the School Act has specific language around school tax exemptions for approved and eligible alternative energy power projects.[1] We recommend the District of Squamish have its municipal solicitor review this section of the School Act to ensure this is an option. It is worth noting that under the "Utility" land classification and the "Business and Other" classification, municipal and school taxes combined typically account for over 90% of the total mill rate.

7.9 Sensitivity and Scenario Analyses

We conducted various sensitivity analyses on:

- Capital costs
- Loads
- Rate of development
- Financing
- Property taxes
- Biomass and electricity input prices

Results are summarized in Table 19. The sensitivity analyses illustrate several things.

- In the absence of other efficiencies, a municipal ownership model (100% debt financing and property tax exemption) results in lower levelized costs. In the case of biomass the levelized cost is almost equivalent to the BAU cost assumptions under a municipal finance model, before grants.

- Estimated property taxes represent a significant cost and a permanent (similar to Dockside) or temporary (similar to Lonsdale Energy Corporation) property tax exemption could also help a private ownership model. It is important to note these property taxes would not be collected from on-site systems in the BAU scenario.

- All options perform better if development is more rapid. Further refinement of the staging of infrastructure is required in the detailed design phase to better time capital expenditures with load growth.

- The levelized cost of cogeneration is highly sensitive to the value of the electricity output. Higher Standing Offer prices or feed-in prices specific to biomass cogeneration could improve the ranking of co-generation.

- The cost of biomass energy will be somewhat sensitive to the price secured for biomass fuel supply. Further work will be required to determine long-term biomass fuel sources and prices.

- Securing other community benefits could help all options. For example, securing some cooling loads to offset the capital costs of the Ocean Heat system could improve the economics of that option. The cooling credit reflects the avoided capital costs of chillers at a small number of commercial sites, assuming these are relatively close to the energy centre and/or ocean water loop.

Table 19: Sensitivity Analyses on Levelized Costs ($/MW.h)

All numbers are for Area A + Oceanfront + Watefront Demand Scenario

Scenario	Levelized Price		
BAU		90 – 100	
	Biomass	**Ocean Heat**	**Cogen**
Base Case	128	145	161
No property taxes	119	137	152
Faster demand	97	117	123
Higher demand (+10%)	118	135	149
Lower demand (-10%)	139	157	175
100% debt financing	113	129	144
100% debt financing, no property tax	105	121	134
Increase total contingency to 10%	132	150	166
Higher biomass prices ($15)	133		
Lower biomass prices ($10)	125		
Cogen SOP initial price of $100			156
Cogen SOP initial price of $110			151
Cogen SOP initial price of $120			145
Ocean heat electric prices increase (+20%)		148	
Ocean heat cooling credit (-$2 MM)		140	
Ocean heat cooling credit (-$4 MM)		134	

7.10 Grant Requirements

Except in a few scenarios, the price that would need to be charged exceeds the target benchmark energy costs for customers. Many district energy systems have attracted government grants in recognition of innovation, environmental and community development benefits. In Table 20 we show the estimated grant required to generate a levelized cost equal to ~ $100 / MW.h for different supply scenarios, which we have used as a competitiveness threshold. A lower grant is required under a municipal financing model with no property taxes. We also show the grant requirement as a percentage of total capital (build out). Grants range from 5 to 35% of capital under the municipal finance model and 30 – 50% capital under the private finance model. The private finance model could also be assisted by a property tax exemption. The biomass strategy has the lowest grant requirements, followed by Ocean Heat and Cogeneration. The grant requirements for Ocean Heat may be reduced by further optimization in the design stage. Cogeneration could also be helped by a higher price from BC Hydro for the electricity output from BC Hydro.

Table 20: Grant Requirements ($2010 thousands)*
(Area A + Waterfront + Oceanfront Development Scenario)

	Biomass	Ocean Heat	Cogeneration
Base Case Scenario	8,600	13,800	18,500
% of total capital	30%	41%	50%
Municipal Financing Scenario	1,900	8,300	13,400
% of total capital	7%	24%	36%

8.0 Implementation

8.1 District Support and Policy

There are several immediate decisions / activities required to advance district energy in Squamish. The first is to establish Council and community commitment in principle to the concept of a district energy system. Regardless of who ultimately owns and operates the system, or the form of alternative energy technology, the District has a key role to play in developing policies to facilitate and promote district energy. This may include:

- Establishing target core service area boundaries (whether mandatory or voluntary);
- Cultivating community support for a system and the specific technologies that may be employed;

- Developing measures to promote or require interconnection of private buildings to the system;
- Establishing commitment to interconnect municipal buildings where relevant;
- Creating mechanisms to promote and support efficient planning and coordinated installation of infrastructure;
- Establishing policies and programs to encourage and facilitate access to energy resources within the community (e.g., biomass);
- Facilitating the selection of site(s) for energy center(s); and
- Establishing policies regarding property taxes and franchise fees for the district energy system.

If the District owns and operates the system, there may be the ability to utilize a service area bylaw to secure loads for the system, similar to North Vancouver (LEC) and Vancouver (SEFC). The District has already commissioned some analysis of bylaw options.

In addition to a policy framework, the District must also make a decision regarding ownership and operation. This could be made prior to any further design and development work, or deferred until further design and development work is completed. Deferring this decision would involve some short-term cost and risk for Squamish taxpayers, although this would be recoverable if the system proceeds to development.

Regardless of who ultimately owns and operates the system, the most critical activities in the near term will be securing loads and designing / developing the distribution system and natural gas boiler capacity. We have identified several viable alternative energy opportunities. Biomass shows some of the best potential in terms of costs, GHG emissions, and local economic development benefits. However, a final selection and implementation of the alternative energy source is not required for several years until loads reach a suitable threshold. Some key analyses / data that may inform the final technology selection include the following.

<u>Biomass</u>

- Confirm amount and price of supply / supply chain development
- Identify any grants specific to biomass
- Community acceptance of biomass heat (and potentially cogeneration)

<u>Ocean Heat Recovery</u>

- Confirm long-run electricity input price forecast (BC Hydro has submitted an application for a new stepped Commercial customer rate design)
- Confirm likely ability to capture cooling loads (and value of doing so)
- Confirm technical specifications
- Identify any grants specific to ocean heat

<u>Co-gen</u>

- Establish BC policy with respect to electricity emission factors for natural gas co-gen
- Monitor demonstration projects for small-scale biomass co-generation (gasification technology)
- Monitor upcoming price changes for Standing Offer and future BC Hydro calls for community-based biomass energy
- Identify local electricity system benefits that could be monetized in project and other grants specific to co-gen

Competitive tender processes should be utilized as part of the final technology / vendor selection process.

8.2 Ownership Options

There are essentially four general ownership models for district energy.

- 100% District Ownership
- 100% Private Utility
- A Hybrid Structure (Public – Private Partnership
- Community Partnership (Cooperative / Non-Profit)

There are several ways to structure District ownership. For example, North Vancouver created a wholly-owned subsidiary (Lonsdale Energy Corporation). The City of Vancouver rolled the SEFC NEU into an existing department, but set up separate accounting systems to track costs. In addition, the City of Vancouver chose an accounting and rate setting structure that emulates a private utility (includes property taxes and a notional return on equity comparable to a private company) in order to ensure equity with taxpayers not served by the NEU and to provide flexibility to divest of the utility in the future. However, the City may eliminate or defer certain transfers if rates exceed their target cap of 10% above electricity. District ownership could include outsourcing of operations to the private sector. For example, LEC contracts out certain services to Corix Utilities.

Central Heat (downtown Vancouver), Dockside Green and UniverCity are examples of privately run utilities. Private district energy utilities are regulated by the BC Utilities Commission (BCUC). They must have a Certificate of Public Convenience and Necessity from the Commission and are subject to regulatory oversight of costs and rates. Municipally owned systems are not regulated by the BCUC.

There are several hybrid (public-private partnership) structures, ranging from joint ventures to division of assets and contractual relationships. Joint ventures are more complicated structures. An example of separate asset ownership would be a situation where the District owns the distribution assets (and responsibility for customer service) and purchases heat from a privately owned energy centre under contract. This model transfers some risks and financing requirements to the private sector. It is also likely exempt from BCUC regulation.

Community partnership models or cooperatives for district energy are untested in B.C. The most notable example of this type of ownership structure is St. Paul District Energy, described in the case studies contained elsewhere in this report.

There are pros and cons associated with all ownership structures (Table 21). The best ownership model will depend in part on the local system context as well as community objectives. Community ownership has historically been more common, due in part to the synergies with community planning and development goals. Communities are often in a better position to manage risks associated with securing loads and coordinating infrastructure, particularly in the early days of developing a new system. Communities can also more easily internalize broader community benefits in the business case (GHG reductions, local resource recovery, local economic development, etc.) and often have greater access to grants (Table 22) and low cost financing. However, private ownership or involvement offers access to experience, economics of scale in equipment procurement and operations, and other sources of financing. Private ownership has been much easier to implement in large master planned developments such as UniverCity at Simon Fraser University, East Fraserlands in Vancouver, Fraser Mills in Coquitlam, and Dockside Green where core loads can be secured through a single developer commitment / agreement.

Table 21: Comparison of Ownership Options

		Option 1 (100% District)	Option 2 (Hybrid)	Option 3 (100% Private)
	BCUC Regulation*	No	Likely not (will depend on structure)	Yes
NEU Viability/Rates	Financing Costs	100% debt financing (typical)	Mix	60/40 debt equity financing Potentially higher cost of debt 10% allowed return on equity Must pay income taxes (may add 3 – 5% to lifecycle costs)
	Grants	More available to District	Additional P3 funding possible	Fewest available (currently)
	Coordination	Easy	Easy	More difficult
	Operations	Synergies with municipal operations	Leverage both private and public operating synergies and experience	Synergies with larger private utility operations More experience
District Taxpayers	District Financing	$20 – 30 million	$10 – 20 million	None
	Operations	Additional staff required	Small increase in staff	None
	Risk/ Liability	Full business risks (but also some control over risks such as load additions)	Some sharing with private sector	Transfer to private sector
	Control	Most	More	Limited to policy

Table 22: Key Grant Opportunities

	Funds	Eligible Costs	Eligible Recipients	Timing
PPP Canada	Grants or repayable contributions	Up to 25% of direct construction costs	P3 with sponsorship by a municipal government	Deadline for first round was October 09. Next round to be announced.
FCM Green Municipal Fund	Grants and low-cost loans	Grants for feasibility / field tests. Loans on infrastructure	Municipalities	May announce program for DE after March 10
BC ICE Fund	Grants for innovative technology	Up to 1/3 of approved project costs (total government sources not to exceed 75%)	Private and public. Only available to pre-commercial technologies or commercial technologies not yet used in B.C.	Next round by June 2010
UBCM Innovations Fund	Grants with no fixed limit	Capital, engineering and design, permitting, monitoring	Local governments (non-profit and P3s under certain conditions)	Another round anticipated in 2010.
PowerSmart Sustainable Communities	Grants	Feasibility, design and capital for energy centres and distribution	Local governments. Private parties not eligible.	Starting in 2010

Note: NRCan TEAM Grant and Clean Energy Technology Funds are no longer available. Sustainable Technology Development Canada only funds pre-commercial technologies. BC Bioenergy Grants not relevant given proposed heat source at Squamish. Small grants of ~$10k are available from MCRED for infrastructure planning by municipalities and regional districts.

In the case of Squamish, there are broader community benefits associated with a biomass energy system, which suggests a key partnership role for the community in the development of a district energy system. The anticipated rate of development and multiple owners in the target neighbourhoods may necessitate some form of District ownership involvement, whether full ownership or via a private public partnership.

If Squamish chooses to pursue a private ownership model, the District will still have a role to play in policy development to support district energy and in securing a private partner. UnverCity and East Fraserlands in Vancouver provide examples of the process for securing a private partner. The general steps include:

- Prepare and issue a Request for Expressions of Interest.
- Evaluate responses and select a partner (Note: Evaluation at this stage is largely based on partner suitability, capability and resources).
- Negotiate a Memorandum of Understanding (MOU) for due diligence phase.
- Partner conducts due diligence and prepares an updated business case (including possible consideration of other technological solutions, if appropriate).
- District reviews partner due diligence (provide input throughout).
- District prepares policy framework to support system (in parallel with due diligence).
- District and partner negotiate an Infrastructure Agreement to develop system, including provisions for securing loads.
- Partner submits application for Certificate of Public Convenience and Necessity and rates to the B.C. Utilities Commission.
- Construction and operation (ongoing regulation by BCUC).

Regardless of the ultimate ownership model, we also believe there is a role for involvement by local First Nations, particularly in light of First Nations existing involvement in the local biomass supply chain.

8.3 Further Optimization of the Business Case

The business analysis is based on pre-design indicative cost estimates. It is intended to justify the next level of design and analysis. During the detailed design phase there will be a number of potential areas for additional optimizations to improve economic, environmental and social outcomes and reduce risks. Some of these opportunities include the following.

- **Solar Domestic Hot Water (DHW) Integration.** Solar DHW could only provide a fraction of annual energy within the site. However, it is possible to integrate solar DHW into the system. The existence of a district energy system would offer opportunities to upsize individual building systems to take advantage of sharing opportunities across sites, something that is not possible with stand-alone building systems. There are three solar DHW systems within SEFC and one within LEC. However, in evaluating the costs and benefits of solar DHW it is important to consider the other alternative resources that may be implemented. It would be inefficient to invest in solar DHW systems if these displace supply from other green energy sources. Squamish would be better off focusing investments in solar DHW into neighbourhoods and buildings not already served by green energy sources. In the case of SEFC and LEC, the solar DHW is expected to displace natural gas consumption in the summer months.

- **Siting of the energy centre(s).** A final site selection must be made in the detailed design phase based on a more detailed phasing plan. At that time, Squamish may also consider multiple energy centres. However, it is important to consider trade-offs between the economies of scale / simplicity associated with a single energy centre and the additional flexibility / complexity offered by multiple energy centres.

- **Distribution system layout and staging.** There will be many opportunities to optimize both the distribution layout and actual sizing and staging of capital equipment in the detailed design phase.

- **Energy Centre equipment sizing and phasing.** A more detailed analysis of equipment sizing and staging will be required based on the targeted loads (and expected security of loads), development phasing, and technology selection.

- **Additional services.** There may be opportunities to optimize the business case through additional services. For example, if Squamish pursues ocean heat, there may be opportunities to improve economics through the introduction of limited commercial cooling to loads near the energy centre and/or ocean loop. If Squamish pursues biomass, there could be opportunities to also utilize biomass heat output for cooling in absorption chiller technology.

- **Grants and other support.** Grants will be required to ensure cost competitiveness. Grant opportunities may vary depending upon the final ownership decision and technology selection. In addition to grants, there may be opportunities to secure additional revenues through the sale of offsets (e.g., Offsetters and Pacific Carbon Trust).

Attachment A – Detailed Case Studies

Southeast False Creek, Vancouver, BC

1. Introduction

South East False Creek (SEFC) is an 80-acre waterfront industrial brown field site near downtown Vancouver. In March 2005, Vancouver City Council approved an Official Development Plan for a sustainable, mixed use community. SEFC will eventually contain about 6 million square feet of development. About 90% of floorspace will be residential with a population of approximately 16,000. A 15-year development timeframe is currently anticipated for the full site. Phase 1 of the development is home to the Athlete's Village for the Vancouver 2010 Winter Olympics. The Village will be converted to market and social housing post-games.

As one tool to achieve its sustainability goals, the City created the SEFC Neighbourhood Energy Utility (SEFC NEU) to produce and distribute hot water for space heating and domestic hot water in buildings. There were three key goals for the creation of NEU: provide reliable, comfortable and cost competitive thermal energy; lower GHG emissions; and reduce the use of high-quality energy (electricity) for the provision of low-grade space and hot water heating.

2. Technical Overview

The SEFC NEU consists of an Energy Centre, a buried network of insulated hot water distribution pipes, and energy transfer stations (ETS) within individual buildings.

The internal heat distribution systems inside buildings (Secondary Side of the ETS) are the responsibility of building developers. They must typically be designed to provide the district heating system (Primary Side) with ΔT (delta T) of at least 40°C on peak winter days and 15 to 20°C in summer.[14] The internal heat distribution system must be designed to provide the in-suite space heating and heating of ventilation air requirements for individual suites, hallways/stairwells and other common areas in the building from the ETS for each site. The DHW system must be designed to provide all DHW requirements for the individual suites and for all common areas in the building from the ETS for each site. Some buildings use DHW storage tanks. Others rely on instantaneous DHW. The instantaneous systems require more heat plant capacity but eliminate the need for on-site storage and can in some circumstances increase system efficiency.

Within individual suites, space heat may be provided via one of three general approaches at the discretion of the developer: 1) hydronic radiant (e.g., under-floor or ceiling panel); 2) fin type baseboard convectors / perimeter radiators, and 3) fan coils. Fan coils are typically used where both heating and cooling is required, although radiant cooling systems are also available. However, radiant cooling systems are relatively new in Canada and their performance has not been rigorously tested (particularly in residential construction). Radiant systems have lower heating supply temperature requirements (and higher cooling supply temperature requirements) but also typically cost more. In the Olympic Village the developer choose a capillary ceiling mat system for providing both radiant heating and cooling. Chilled water is provided by on-site chillers as centralized cooling did not meet economic thresholds.

The district system employs a temperature reset strategy to maximize the efficiency of the distribution system and to meet the design requirements of many buildings, particularly older buildings. For most of the year, the operating temperatures are fixed based on the minimum temperature required for DHW (65°C), eliminating the need for any ancillary heating equipment in buildings. However, when outdoor air temperatures fall below 0°C, the district heating supply temperature is ramped up, typically to a maximum of 95°C to increase ΔT and thereby increase supply capacity as necessary. In the Lower Mainland climate, there will be only a few days per year when the supply temperature reaches its maximum design level of 95°C. At the maximum supply temperature the district heating ΔT will be 40°C. This design is used to maximize both efficiency and staffing flexibility. The ability to ramp up temperatures during cold periods helps to minimize pipe diameters and pumping energy requirements. The distribution system flow is also varied to maintain a desired pressure differential at the furthest points in the system.

Each ETS consists of heat exchangers and an energy meter. The NEU bills building owners. They are responsible for internal allocation of bills among tenants or strata owners. A form of sub-metering has been installed by developers for the Vancouver

[14] The ΔT is the difference between the supply and return temperatures and reflects how much energy is extracted from a given quantity of water.

Olympic Village (a portion of the SEFC NEU). The Olympic Village is not yet operational, so there are no local data regarding the effects of sub-metering.

Three buildings will also have solar thermal panels to produce domestic hot water. Any excess hot water not required by these buildings is exported to the district energy. Buildings with solar domestic hot water will receive a net metering credit for energy exported to the grid. The credit is based on expected value of heat in terms of displaced gas usage during the summer.

After screening several alternative energy sources, the City short listed sewer heat recovery and biomass as preferred alternatives. Sewer heat recovery is a less proven technology than biomass. However, based on the unique opportunity to integrate heat recovery with a new sewer pump station and given development timelines driven by the Olympics, the City selected sewer heat recovery for Phase 1. A fully natural gas-fired system was not considered as this did not meet environmental objectives since business as usual heating in Vancouver already involves a high proportion of electric heat with lower GHG emissions.

There are many systems worldwide that recover heat from treated sewage. There are fewer that recover heat from raw sewage. The recovery of heat from treated sewage is easier, but treatment plants are rarely located close to heat loads. Technology is available to extract heat directly from sewers (e.g., Rabtherm). However, this requires large mains with sufficient length and sewage flows. There is a need for secondary loops to transfer heat from heat exchangers to heat pumps. The capital costs of this technology are generally prohibitive unless sewer mains are being installed or replaced for other reasons.

SEFC presented a unique opportunity for an alternative approach to recovering sewer heat. The site had an existing sewer pump station that needed to be expanded and re-located to accommodate the new development. Co-locating the Energy Centre with the sewer pump station allowed the City to make use of a direct heat exchange process between the sewage and a heat pump, eliminating the need for secondary loops and glycol intermediary fluid and increasing overall efficiency. There are only three sewer heat recovery systems worldwide that recover heat from untreated sewage, two in Oslo, Norway and one in Tokyo, Japan. The Oslo plants have been operating since 1991 and 2006, respectively.

Sewer heat recovery is similar to a geo-exchange system in that an electric heat pump produces useful heat for space heating and domestic hot water using a low grade heat source. Compared to geoexchange, however, sewer heat recovery is more efficient due to higher heat source temperature and lower installation costs. In SEFC, the annual sewage temperature averages 18°C, about 10°C warmer than the ground, increasing the efficiency of the heat pump. The primary challenge associated with this form of sewer heat recovery is management of sewage solids and biofilms, which requires a local pretreatment and cleaning system. The schematic provides an overview of the process. The system relies on natural gas boilers to augment heat produced from the heat pump on very cold days. Natural gas boilers also produce energy when system demands are too low to use the heat pump.

The sewer heat pump is a custom installation supplied by Trane through a competitive bidding process. The sewer heat pump has an expected average annual co-efficient of performance (COP) of 3.2. Given the higher cost of heat pump capacity, the sewer heat recovery is sized to maximize annual utilization; in this case, it is sized to about 25% of diversified peak demand.[15] At this size, the heat pump is expected to supply 60 – 65% of the community's annual energy requirements.[16] The remainder will be met with natural gas (and some domestic solar hot water). Heat pump capacity is currently planned to be installed in two equal increments (2.7 MW each), one at start up and another at approximately 2015 when loads reach about 90% of build out.

3. Financial and Environmental Outcomes

<u>Loads and Capital Phasing</u>
The project is broken into roughly three phases. About one-third of the load will come on line in Phase 1.The majority of this floor area is in the Olympic Village, together with several new buildings on private lands surrounding the village. This is a somewhat unique situation with a large upfront load, which made immediate implementation of the alternative energy source more economic.

The distribution mainlines have been installed. The system has been providing heat to several buildings using temporary boilers since the spring of 2009. The permanent Energy Centre hsa been commissioned and has been fully operational since January 2010.

The tables below summarize the key financial and environmental outcomes of the utility. Phase 1 capital is largely confirmed. However, all other values are forecast. Sales are based on average weather and can fluctuate across individual years.

[15] The heat pump is a higher proportion of demand at start-up because it is being installed from the outset.
[16] The amount of annual energy provided is limited by the capacity of the heat pump relative to total load, as well as by the turn down capability of the heat pump. During periods of very low demand (e.g., off-peak summer hours), the minimum heat pump output may exceed demand and will therefore not be dispatched. In these cases, demand will be met by natural gas.

Forecast Phasing of Demand and Heat Plant Capacity

	2010	2015	2020	2025
Annual Heat Sales (MW.h)	16,304	56,389	63,691	63,691
Diversified Heat Demand (MW)	6.1	21.2	23.9	23.9
Total Installed Heat Plant Capacity (MW)	18.2	26.9	29.4	29.4
Sewer Heat Pump Capacity (MW)	2.7	5.4	5.4	5.4
Natural Gas Boiler Capacity (MW)	15.5	21.5	24	24
Estimated % of Annual Energy Provided by Sewer Heat Pump	~60%	~65%	~60%	~60%

Projected Capital and Operating Costs

All dollar values in thousands of $2008	2010	2015	2020
Cumulative Capital Expenditures (Before Grants)	29,500	40,942	43,233
Operating Costs (Before Interest and Depreciation)	1,316	3,107	3,657
$ / MW.h	81	55	57

Actual Phase 1 capital costs for the DPS and ETS infrastructure were equal to or lower than the estimates used for the original business case. The actual Phase 1 Energy Centre costs were approximately 25% higher than the original budget estimate. This reflects in part the difficulty of estimating the cost for a custom engineered plant, including a custom engineered industrial heat pump. However, mechanical equipment costs were within ~10% of original estimates. The main cost overrun was associated with the building structure. Following the original business case, the building was designed to meet a LEED Gold standard, which increased building costs. In addition, architecture design as greatly enhanced and an interpretive centre was included. Finally, a considerable portion of equipment was installed sub-grade to fit the final site selection under the Cambie Street Bridge. These cost overruns, however, were offset by much higher grant contributions than anticipated in the original business case ($8.5 million vs. $2 million). As a result, the total budget did not exceed the one originally approved by Council.

The other major change was a reduction in Phase 1 loads as a result of some delays in private developments around the Olympic Village following the market downturn. Build out loads have not changed, but as a result of the deferred developments there will be some excess Energy Centre capacity for several years.

<u>Financing</u>

Phase 1 is financed through an FCM loan, grants and City Debentures. The NEU is entirely self-financing through NEU revenues. There is no contribution from general taxes anticipated. The NEU is expected to earn a long-term pre-tax rate of return equivalent to a benchmark private utility regulated by the B.C. Utilities Commission (~7.8% weighted average total return on investment over 25 years).

Phase 1 Financing

Source	Value
FCM Loan	$5.0 million
Grant	$8.5 million
Debentures	$16.0 million
Total	$29.5 million

Return Benchmarks

The original business case developed based on estimated loads, capital costs and operating expenses. In the pro forma, revenues were set equal to an estimate of business as usual heating costs. In this case, electricity prices were used as a benchmark because of the prevalence of electric heat in multi-unit residential buildings in Vancouver and the public's familiarity with electricity prices.[17] Council decided that up to a 10% premium over electric heat would be acceptable given the other benefits of the district energy system, including comfort, reliability, elimination of on-site equipment and associated maintenance and environmental improvements. No allowance was made for any additional in-building costs associated with implementing hydronic systems vs. electricity systems. No consensus was reached on the magnitude of such costs and staff felt that while electric heat provided a reasonable benchmark for revenues, it was not a realistic base case for building construction given other commitments for the neighbourhood.

The pro forma was used to estimate an unlevered return on investment (ROI) or internal rate of return (IRR) for the project over 25 years based on estimated revenues and costs. Because the City wanted to ensure the utility was self-supporting and that it could exit from the business if it wished at some later date, all explicit and implicit carrying costs were added to the pro forma, including property taxes (not normally paid by City-owned utilities, corporate overheads, and insurance (the City is self-insured). Future capital requirements were included in the pro forma. No terminal value was added after 25 years (the average life of major equipment except DPS equipment) so the analysis was considered conservative.

The unlevered IRR was then compared the two different benchmarks. The first benchmark was the City's expected long-term cost of borrowing (6%). This represents the minimum IRR required to cover debt service costs under 100% debt-financing, assuming no premium for risk or a debt guarantee. The second benchmark was the weighted average cost of capital (WACC) for a comparable private utility in B.C. The BC Utilities Commission regulates public energy utilities in B.C. Examples include electric utilities such as BC Hydro and FortisBC (municipal electric utilities are currently exempt from BCUC regulation) and gas distribution utilities such as Terasen Gas Inc. (TGI), Terasen Gas Vancouver Island (TGVI), and

[17] In reality, natural gas is used for domestic hot water and make-up air, which still accounts for a large portion of building heating demand. Natural gas is also used in most commercial spaces. However, the lifecycle cost of natural gas heat, including fuel and boiler capital is currently fairly close to electricity. Electricity was therefore used as a reasonable benchmark.

Terasen Gas Whistler (TGW). The Commission sets rates for these utilities based on approved operating expenses, capital expenditures, and financing costs. Financing costs are based on an approved capital structure, weighted short-term and long-term interest rates, and an approved Return on Common Equity (ROE).

For the purposes of the private utility comparison, the City used the approved capital structure and ROE for Dockside Green Energy, a newly formed district energy utility in Victoria owned by Dockside Green Energy LLP (jointly owned by VanCity Capital Corporation, Windmill West Properties, Corix Utilities Inc. and Terasen Energy Services Inc.). As a private utility, Dockside is regulated by the Commission. In its recent Decision, the Commission approved a capital structure that has 40 percent equity and ROE that is 100 basis points higher than the benchmark ROE that the Commission establishes for a low-risk benchmark utility (which currently produces an allowed ROE of approximately 9.62% (pre-tax). Using a long-term cost of debt of 6.5% (for a private utility), this implies a nominal WACC of approximately 7.8%. The City's decision to proceed with the NEU was based on achieving an unlevered IRR of approximately 7.8%, assuming rates equal to electricity plus a 10% premium and taking into account all explicit and implicit operating expenses. Revenues reflected a forecast of long-term retail electricity prices recently filed by BC Hydro with the Commission.

For the final rate setting exercise, the City used its own cost of debt (including the low-cost FCM loan) and an implicit return on equity payment.

<u>Rates</u>
The City opted for a two-part rate structure – a fixed monthly charge per m2 of connected floor area and a variable charge based on actual metered usage. Fixed NEU costs (debt service, depreciation, staff, etc.) are allocated to the fixed fee. Variable NEU operating costs are allocated to the variable charge. Roughly two thirds of the NEU costs are fixed.

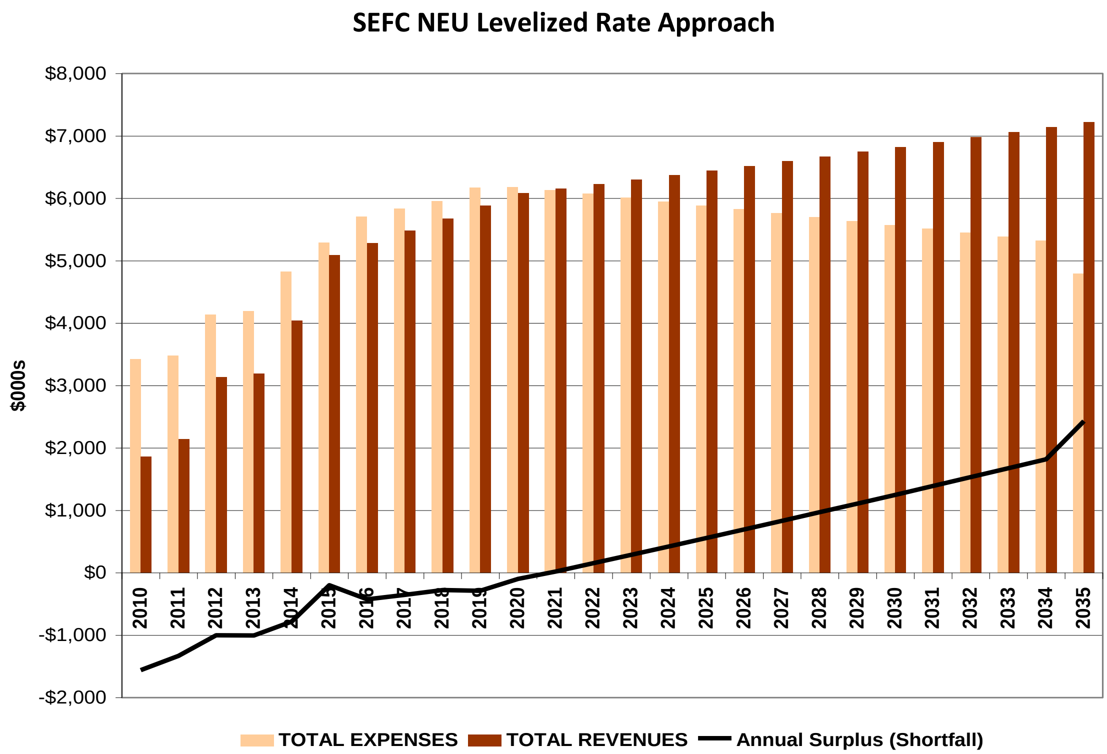
SEFC NEU Rates (2010)

	Starting Rate	Escalation*
Capacity Charge	$0.44 / m2 / month	~1.15% above inflation
Energy Charge	$37 / MW.h	~1.15% above inflation

*Electricity prices in B.C. are currently expected to increase 50% above inflation in the next 10 years as a result of maintenance requirement for aging assets, load growth, and the higher marginal costs associated with new green electricity supplies (relative to the low remaining embedded costs of large heritage hydroelectric facilities).

Based on the rates above, connected floorarea and average expected energy intensity (under full occupancy), the effective unit rate works out to ~$85 / MW.h of heat supplied.

In order to ensure competitive rates the City opted for a levelized rate structure. That is, rates are set to within 10% of a benchmark price for electricity initially and escalated somewhat above the cost of inflation over time. Projected escalation of NEU rates is still somewhat lower than projected escalation of electricity in B.C. This approach results in under-recovery of revenue requirements in early years and modest over-recovery in later years. The deficit in early years is financed through a rate stabilization account. Levelized revenues are expected to equal levelized costs over the 25-year rate setting horizon.



Emissions

Given this is a new development the calculation of GHG emission reductions requires some assumption about a base case. In Vancouver a large portion of multi-residential buildings are built with electric resistance heating. However, recent studies have shown these buildings still utilize a high portion of natural gas for space heating via gas-fired make-up air units. Domestic hot water tends to be produced largely with natural gas. Where cooling is required, natural gas is often used to maintain the temperature of water loops for distributed heat pumps in winter months. Given base case assumptions and the low GHG intensity of electricity in British Columbia, the City estimates the project will reduce GHG emissions 50 – 60% relative to business as usual.

SEFC NEU GHG Impact (tonnes / year)

	2010	2015	2020
Business as Usual GHG Emissions (Estimated)*	3,496	12,013	13,581
NEU GHG Emissions (Estimated)	1,523	4,330	5,923
Reductions Associated with the NEU	**1,973**	**7,683**	**7,658**
% Reductions	**-56%**	**-64%**	**-56%**

*Assumes natural gas heating in most commercial spaces and electric space heating in a large majority of residences, with natural gas make-up air units and domestic hot water boilers. Recent building studies suggest a high portion of annual space heating requirements in buildings are provided by the make-up air units rather than electric baseboards due to pressurized corridors and other design practices.

4. Institutional Overview

In March 2006, after a pre-screening and full feasibility study and business case completed by Compass Resource Management and FVB Inc., Vancouver City Council approved in principle the creation of the False Creek Neighborhood Energy Utility (NEU) to provide space heating and domestic hot water to multi-family residential, commercial, institutional and industrial buildings in SEFC. The feasibility study also considered possible extension of the NEU to the nearby False Creek Flats and North False Creek neighborhoods. These extensions will be considered as development of these neighbourhoods proceeds.

The first phase of development of the NEU will recover heat from a newly relocated and expanded sewer pump station. This will be the first use of this technology in North America, and one of only four such projects in the world. This proved economic because it was coordinated with a planned relocation and expansion of the pump station and because of the large initial loads created by the development of the Olympic Village. In addition, the NEU will also take excess heat from roof-top solar modules in at least three SEFC buildings. These modules are sized to produce more heat than can be utilized on-site in the summer months. The existence of a local district energy system allows this excess heat to be utilized for other buildings in the summer months. Buildings exporting heat to the district energy grid will receive a net metering rate for their net production.

Given the development timelines for the Olympic Village and associated community infrastructure, and the linkages with the municipal sewer pump station relocation, Council approved interim financing for the development of the Phase 1 infrastructure, including primary distribution mains and the Energy Centre. Council did not make any final decisions regarding the ultimate ownership and operation of the NEU.

In December 2006, Council reviewed an assessment of different ownership and operating strategies for the NEU, and approved the continued ownership and operation of the NEU by the City. Council approved the integration of the NEU into the existing Engineering Services Department (as opposed to a stand-alone entity), with governance of the utility shared by the General Manager of Engineering

Services and the Director of Finance. Council also approved a recommendation that the merits of continued ownership by the City be reviewed before any significant expansion of the NEU, and, in any event, within three years of the commencement of commercial operations. Finally, Council approved preliminary rate design principles as follows:

1. Full cost recovery
2. Fair
3. Understandable and cost-effective
4. Allow for two separate rate classes
5. Price signals to encourage conservation
6. Customer rate stability
7. City revenue stability
8. Rates adjusted annually

Because the NEU is municipally owned, it is currently exempt from regulation by the B.C. Utilities Commission. Private district energy firms such as Central Heat in downtown Vancouver and Dockside Green in Victoria are regulated by the Commission under a cost-of-service model with posted tariffs (rather than long-term contracts as is common in some other jurisdictions). The City opted to establish financial accounts and rates similar to those of a private utility in order to provide maximum flexibility for selling the asset and to ensure City tax payers were compensated for risk. The NEU is required to pay property taxes much like a private utility and rates assume a capital structure and regulated return on equity comparable to private utilities. This is currently set at 60% debt / 40% equity, with an approved return on equity of ~3.6% above long-term debt rates. There is currently no allowance for income taxes that may be payable by a private company.

In November 2007, Council approved the creation of the *Energy Utility System Bylaw,* which requires interconnection of all buildings within SEFC. In October 2008 Council approved an amendment to this bylaw, primarily in order to enable the NEU to recover costs associated with the supply of pre-occupancy heat services to the Olympic Village, and to base the monthly levy on floor area.

In March 2008, Council approved the initial rate design for the NEU and a long-term financing strategy and operating plan for the NEU. Re-evaluation of ongoing City ownership will take place by 2013.

Design and installation of distribution piping commenced in August 2006, prior to a final decision regarding the location and technology for the Energy Centre. Construction of Energy Transfer Stations for the initial buildings commenced in June 2008. A final decision was made regarding the Energy Centre technology in April 2007 and detailed design commenced in July 2007.[18] Construction of the Energy Centre commenced in September 2008. Interim heat is being provided by a temporary gas-fired boiler plant. Commissioning of the permanent Energy Centre is

[18] Both sewer heat recovery and biomass were being considered until the final selection was made to proceed with sewer heat for Phase 1.

anticipated in October 2009, in time for the Olympics in February 2010. Future expansions are anticipated as additional development proceeds. Voluntary extension to existing customers at the periphery of the NEU service area with compatible heating systems is being explored as their existing plants require replacement. Expansion of the NEU to new neighbouring communities is also being contemplated.

5. Energy System Utility Bylaw

Early in the business case development, the City identified the connection of area loads as the most significant risk to the viability of the NEU. The City's green building policy provides some incentive for interconnection because it recognizes the benefits of district energy in establishing compliance. Other communities in B.C. operate under the authority of the Community Charter, which enables them to establish mandatory connection bylaws under certain conditions. For example, the City of North Vancouver has made connection to Lonsdale Energy Corporation mandatory within established service areas.[19] Given the significant investment required by the City and given the fact the NEU will serve only a portion of the City rather than all taxpayers, Council instructed staff to seek amendments by the Province to the Vancouver Charter to enable it to also make connection mandatory.

The Province of British Columbia amended the Vancouver Charter in the spring of 2007 to provide the City with authority to provide energy utility services. Subsequent to this, the City enacted the *Energy Utility System By-law*. Beyond basic provisions required to regulate energy services, the by-law makes connection to the NEU mandatory for all new buildings within the SEFC Official Development Plan area. As with the City's water, sanitary sewer and solid waste utilities, City Council is the regulatory body for the NEU. Municipal utilities are not regulated by the BC Utilities Commission. Council has approved an extension policy to permit voluntary connections beyond the current service area if deemed in the public interest.

6. Some Lessons Learned

The SEFC NEU has just commenced commercial operation. However, some key lessons learned through the planning and development phases include the following:

[19] The Community Charter provides that a council may provide any service that it deems necessary or desirable and may by bylaw "regulate, prohibit and impose requirements in relation to municipal services" and "…require persons to do things with their property, to do things at their expense and to provide security for fulfilling a requirement." There is some uncertainty whether energy service area bylaws could be found by a court to establish a building standard "additional to or different from" the BC Building Code, contrary to the Buildings and Other Structures Bylaw Regulation, in that these bylaws implicitly require new buildings to incorporate an in-building hydronic heat piping (etc.) system that works with the service they are required to connect to. There is also some question regarding the applicability and enforceability of such bylaws if a City does not have some ownership of the system. To date, these bylaws have not been challenged.

- During the initial planning phase, it is essential to focus on the application and consider a range of technology solutions in order to select an optimal solution that meets desired outcomes. This is also important in order for stakeholders (and granting agencies) to understand the rationale of a particular technology solution.

- Identifying more than one viable technology in the early stages provides flexibility to optimize systems and address schedule and permitting issues during the detailed design and implementation phases.

- Natural gas will continue to play a role in renewable heating systems given the need for peaking and back-up support and the cost of alternative energy capacity.

- Phasing of technology solution is critical. The large upfront loads offered by the Olympic Village permitted the immediate installation of alternative energy technology but in many cases where loads develop more slowly it will be necessary to install the cheaper peaking and back-up equipment first until loads build to a sufficient level to permit installation of the more expensive alternative technology.

- Exceeding normal design standards for utility-grade buildings can greatly increase building costs. This may be necessary, however, where plants are located in highly compact communities and will be very visible.

- Securing loads is critical for project economics. While there are numerous mechanisms to promote voluntary connection, mandatory connection requirements for at least a core development area can greatly reduce this risk. Once a core area is established and the utility is in place, it will be easier to expand service under a voluntary connection model outside the core area, particularly where expansion can be supported by other policy mechanisms such as green building and other performance requirements that can be met through connection to district energy.

- Working with developers to ensure building designs meet technical specifications of district energy is critical to success.

- The City of Vancouver created considerable institutional capacity by forming an interdepartmental steering committee very early in the process to oversee and integrate the results of studies and actively direct policy development and utility creation. The City is now able to leverage this capacity for expansion of the utility, both adjacent to the current site and the creation of more distant service areas, such as one being considered at East Fraser Lands.

- The City has structured the utility in a manner which provides flexibility for divesting of the asset at a future date. There is considerable interest by private utilities in B.C. to acquire these systems.

Markham District Energy

1. Introduction

Markham District Energy (MDE) is a district energy utility that is a wholly owned subsidiary of City of Markham. The system serves the emerging Markham Centre at Highway 7 and Warden Road, north of Toronto. The utility delivers heating and cooling energy to nearby residential, commercial, institutional and public buildings. Electricity is also generated and fed into the grid with the waste heat directed to the district energy system for additional thermal energy.

MDE became operational in 2001, providing heating and cooling service from the first of four planned energy plants to 3 buildings consisting of 90,000 m2. These anchor tenants were critical for the creation of a viable system. Similar to most utilities, district energy systems require large capital outlays which are recovered over time through customer rates. A large customer base in the early years of system inception can help propel a favourable business case (see Effects of Phasing section in Economic Analysis section of this report).

Currently, MDE serves or has signed long term contracts with all new buildings planned to date in the Markham Centre. In total, approximately 500,000 m2 will be connected, including two community and school buildings, six commercial buildings, fourteen residential highrise buildings, and 175 town-homes. Presently, the system serves approximately 70,000 m2 of residential and 120,000 m2 of commercial.

The ongoing development of MDE is closely tied to the City's vision for a sustainable Markham Centre. Planning for City Centre began in the 1990s and continues today. The Centre vision – described as an environmentally sustainable, transit-friendly, and attractive suburban downtown – will be home to 25,000 residents and provide job space for up to 17,000 employees at the completion of a 20-30 year buildout. Central to the vision of Markham Centre, is an efficient, district energy system that serves all of the anticipated 2 million m2 of mixed use floorspace.

2. Technical Overview

The MDE system consists of heating, cooling and power generation equipment. The heating component consists of 3 natural gas fired boilers with a production capacity of 12 MW. Electricity generation consists of 8.3 MW of reciprocating natural gas−fired engine capacity. Exhaust and jacket heat from the electrical generation equipment is captured and directed to the district energy grid, providing 8 MW of additional thermal production capacity. Cooling equipment consists of 4 centrifugal chillers and one absorption chiller with a combined production capacity of 4,600 tonnes. The absorption chiller is able to utilize waste heat from the CHP units during summer and shoulder season electricity generation to provide cooling for nearby buildings.

MDE recently installed a large thermal energy storage (TES) tank. CHP engines are run during the day to insure peak pricing for the electricity output. The waste heat from the CHP units is stored during the day in the TES tank for use at night when heating demand rises. The use of TES results in avoided natural gas consumption for heating equipment and any related GHG emissions.

Heating and cooling is distributed to nearby buildings via a 20-km network of underground pipes, known at the Distribution Piping System. There are 2 pipes for each of heating and cooling (a supply and return pipe for each).

Energy transfer stations within individual buildings transfer heat from the DPS (primary side) to the in-building distribution system (secondary side). Buildings do not require any on-site hot water boilers or air-conditioning chillers because all baseload and peak/backup equipment is located at the central plant. Avoided customer costs (capital and maintenance) are one of the main benefits of district energy from a customer perspective.

3. Financial and Environmental Overview

There is limited financial and operating data available for the MDE system. We gathered information from existing case studies, previous work Compass completed on rates setting for other projects and consultation with MDE staff.

The district energy system became operational in 2001 at a total capital cost of $16 million. In 2004, MDE received a $5 million investment from the Federation of Canadian Municipalities to help finance a $14 million dollar expansion of the system. FCM funding consisted of a $4 million load from the Green Municipal Investment Fund and a $1.5 million grant from FCM.

In 2007, MDE secured a 20-year power purchase agreement from Ontario Power Authority for a 5 MWe CHP plant that will also provide 5 MWt to the district energy system (Warden Energy Centre).

The New Deal for Cities and Communities distributes federal gas tax revenue to municipalities for eligible environmentally sustainable infrastructure projects. Community energy systems (e.g., district energy) are an eligible project. The City of Markham allocates half of its gas tax grant to district energy infrastructure investment.

MDE secures customers through negotiated contracts. The rate structure is split up into two and sometimes three components as detailed below:

1. Variable Energy Charges - the average cost of heating energy that each customer would have paid using conventional, non-district energy technology. This is calculated each month based on the customers' metered consumption of thermal energy, converted back to notional gas and electricity input volumes using contractually agreed BAU efficiencies and applicable current gas and electric utility rate schedules. Because each building is different, this approach will lead to Energy Rates that vary from customer to customer.
2. A Fixed Capacity Charge – the fixed capacity charge is not more than the customer's avoided operation and maintenance costs plus annualized capital.
3. (Optionally) A separate connection charge – this is an optional charge for institutional customers that do not value the avoided capital costs of connection. For example, they have in their budgets $1 million for a heating plant and perceive no advantage to not spending it. In response, MDE established the optional connection charge. To extend the above example, the institution would pay $1 million to a connection charge instead of embedded within the fixed rate component.

Rates are different across buildings due to different levels of required capacity and different expected equipment efficiency.

Once all four planned energy plants are operational, MDE expects the system CO2 emissions by 50% over BAU per year 78% of NOx emissions.

4. Institutional Overview

The MDE system is regarded as an exemplary model of district energy development by almost all of the supply chain interviewees we consulted with for this report. MDE has successfully integrated energy system planning with broader community plan while taking advantage of loans and grants only available to municipalities. As a wholly owned subsidiary, MDE can access tax advantages available to the private sector for the construction and operation of plants (e.g., an accelerated write-off provision for certain types of equipment used to produce energy in a more efficient way).

Being a subsidiary of the City of Markham afforded MDE a number of benefits during the start up phase of the system. As a municipally owned system, the City had an interest in speeding up the permit and development approval process for the plant site and building, rights of way and building scale connection. Energy plants are located on municipally owned lands which allow MDE to sidestep official plan amendments and the corollary rezoning process. Site plan and building approvals are still required, and MDE still remains subject to noise and emission requirements like any other operator.

In Markham Centre, connection to the district energy system is not mandatory but highly encouraged via the planning approval process. Developers are made well aware in the Development Application process that there are guidelines they are expected to meet to deliver a green project. The City has a point-based development application process. Developers are encouraged to talk to MDE about interconnection, which earns points on the application. Connecting to the district energy service is not mandatory for application approval. MDE presents district energy connection as an option to developers, explaining the rate structure and avoided capital and design requirements to the developer. The developer retains the right to go back to the City and say interconnection is not a good product and they wish to install onsite equipment. According to MDE, to date all developers have connected to the MDE system.

District Energy St. Paul, Minnesota

1. Introduction

District Energy St. Paul started off as a demonstration project in 1983. The initiative was spearheaded by then Mayor George Latimer, who lobbied state and federal governments for assistance in replacing a former steam system with a modern district energy system. The system was designed to be energy efficient, provide local fuel flexibility, and secure stable rates for customers. It was developed through a public/private partnership among the City of Saint Paul, State of Minnesota, U.S. Department of Energy and the downtown business community.

In 1993, District Energy began offering district cooling service to downtown building owners. In 2003, District Energy developed an affiliated combined heat and power (CHP) plant fuelled by urban wood waste. Today, District Energy currently heats more than 185 buildings and 300 single-family homes (2.8 million square metres) and cools more than 95 buildings (1.7 million square metres) in downtown St. Paul and adjacent areas. District Energy now serves twice as much building area as the former steam system it replaced while consuming the same amount of fuel. Rates have been relatively stable and generally below the cost of on-site natural gas heat production.

District Energy St. Paul provides district heat to 185 buildings and 300 single-family homes in their service area as well as cooling to 95 buildings in the downtown core.

2. Technical Overview

District Energy St. Paul utilizes a mix of fuels to providing heating and cooling service to the downtown and generate electricity for the local grid. The mix of fuel and technology mix includes:

- 65-MWt municipal wood waste CHP plant with an electrical capacity of 33 MW,
- 290 MWt capacity consisting of a mix of coal-, oil- and gas-fired boilers

- 33,000 tonnes of cooling capacity consisting of a mix of electric and absorption chillers and two chilled water storage systems . The storage tanks are cooled at night using off-peak electricity.

The biomass CHP electricity is provided to the local grid under a 20-year contract with Xcel Energy.

District Energy has installed the largest CHP plant in the U.S. Approximately 45% of its peak load and 90% of its annual energy load is met with biomass. Excess steam heat produced in the summer is used to run chillers and excess electricity in the winter is exported to the electrical grid.

3. Financial and Environmental Overview

The revamp of the existing steam based system with a coal-fired district heating system came at a cost of $46 million, financed through $30.5 million in revenue bonds, $9.8 million in loans from various government agencies, and $5.5 million in a loan from the Municipality of St. Paul. The $75 million biomass CHP facility was initiated in 1999 and became operational in 2003.

Relative to the old coal-fired plant, the new biomass CHP plant will reduce sulphur dioxide emissions by 60% and carbon dioxide emissions by 280,000 tonnes/year.

The St. Paul's district energy system was lauded by two supply chain analysis interviewees as a district energy success model with a proven track record. The energy provider has an 80% market share of downtown buildings, suggests it can show customers a 25% reduction in energy consumption, and has increased the energy demand and consumption rate by only 0.3%/year over 20 years (compared to 2.7% for natural gas).

District Energy helped underwrite the initial system upgrade by signing customers to long term agreements, eventually signing up the necessary 135 MW of capacity required for the improvements. They did this by working closely with the St. Paul's Buildings Owner and Management Association (BOMA) to communicate the benefits and costs of a long term contract structure. Because the old system was steam-based, existing building had to convert to hot water based systems.

4. Institutional Overview

District Energy is run as a private, non-profit corporation with no shareholders or other owners. Governance is by a Board of Directors with three City-appointed members, three customer-elected members and a seventh member chosen by the other six. District Energy has created several affiliate companies since its inception.

District Cooling St. Paul is also a private, non-profit corporation that provides district cooling service to downtown St. Paul building owners. It is governed by the Board of Directors of District Energy plus one additional member elected by district cooling customers. Ever-Green Energy is a for-profit corporation formed to develop the wood-fueled CHP facility. Today the company manages the operations of District Energy, its affiliates, and another St. Paul district energy system. The company is also involved in a variety of projects related to renewable energy, biomass and deep water cooling. St. Paul Cogeneration owns and operates the CHP plant. Environmental Wood Supply locates, collects, processes and hauls wood waste to the CHP facility. Renewable Energy Innovations is an affiliate of Ever-Green Energy that develops deep water cooling renewable energy projects.

The biomass CHP plant requires 300,000 tonnes/year of wood waste (half of the wood waste generated in the metro St. Paul area). Approximately half of the wood waste is generated in the St Paul's area from downed trees, tree trimmings and branches. Such a large volume of wood waste can pose transportation challenges for a CHP unit located in an urban area. Over 50 trucks per day bring wood waste to the plant. To limit traffic congestion and ensure fast delivery, special hoppers that allow two trucks to discharge simultaneously were installed.

Attachment B – Detailed Capital Phasing Assumptions ($2010 thousands)

Demand Scenario	Biomass				Ocean Heat				Cogen			
	Phase 1	Phase 2	Phase 3	Phase 4	Phase 1	Phase 2	Phase 3	Phase 4	Phase 1	Phase 2	Phase 3	Phase 4
Area A												
Distribution System	-	1,921	112	-	-	1,921	112	-	-	1,921	112	-
Energy Transfer Stations	143	1,059	143	-	143	1,059	143	-	143	1,059	143	-
Energy Centre	245	1,229	2,248	1,229	245	1,229	3,626	1,229	245	1,229	4,406	1,229
Area A + Waterfront												
Distribution System	-	3,701	343	674	-	3,701	343	674	-	3,701	343	674
Energy Transfer Stations	428	1,298	449	343	428	1,298	449	343	428	1,298	449	343
Energy Centre	290	2,565	2,248	4,813	290	2,433	4,020	5,545	290	2,433	4,406	6,839
Area A + Oceanfront												
Distribution System	-	4,702	400	-	-	4,702	400	-	-	4,702	400	-
Energy Transfer Stations	143	1,785	805	-	143	1,785	805	-	143	1,785	805	-
Energy Centre	357	2,984	2,248	6,696	357	2,442	4,140	10,446	357	2,956	5,835	8,791
Area A + Oceanfront + Waterfront												
Distribution System	-	6,483	630	674	-	6,483	630	674	-	6,483	630	674
Energy Transfer Stations	428	2,023	1,110	343	428	2,023	1,110	343	428	2,023	1,110	343
Energy Centre	402	4,320	2,248	10,280	402	3,588	4,140	14,762	402	4,160	5,835	14,401