CREATIVENERGY

Via Email/Mail

June 9, 2017
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck
Commission Secretary

Dear Mr. Wruck

Re: Creative Energy Vancouver Platforms Inc. (Creative Energy)
Long-Term Resource Plan (LTRP)

On June 9, 2015, the Commission issued Order G-98-15 and Decision which, among other things, directed Creative Energy to file a long-term resource plan on or before June 9, 2015.

In accordance with the Commission's Resource Planning Guidelines and section 44.1 of the Utilities Commission Act (the UCA), Creative Energy respectfully submits the LTRP for the Commission's review.

Creative Energy is also filing by separate letter an electronic copy of an economic model used in the Fuel Switch Study, attached as Appendix A to the LTRP. The model is being filed confidentially because it is proprietary and contains commercially sensitive information. All pertinent data and results from the economic model have been included in the public filing.

If further information is required, please contact Anna Peresada at 606 688 9584.

Sincerely,
Creative Energy

Original signed:

Robert Hobbs
President and CEO

Attachments
cc (email only): Registered Parties to the Creative Energy 2016-2017 Revenue Requirements proceeding

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2017 Long-Term Resource Plan

June 9, 2017

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Contents

A. Introduction and Application

1) Creative Energy submits this Long-Term Resource Plan together with the Fuel Switch Study ("LTRP")[1] for the Commission's review and acceptance pursuant to section 44.1(6) of the *Utilities Commission Act* (*UCA*).

2) Creative Energy is a reliable and low-cost provider of thermal energy. Creative Energy's core load is relatively stable. As a small utility serving large buildings in a dense urban core, changes in load are lumpy and hard to predict, reflecting a very localized development and policy context. In recent years efficiency upgrades and other changes among existing customers have been largely offset by the addition of new customers. However, further additions of new customers are uncertain and will depend on a range of site-specific factors beyond Creative Energy's control. The extension of the current network will depend on the location, timing and most importantly sequence of individual new developments in downtown Vancouver. Equally important, energy standards for new development in Vancouver are changing rapidly and diverging significantly from the standards and policies that apply to existing buildings and customers. It is now clear it will be difficult for Creative Energy to connect new loads to the existing network without the addition of low-carbon energy sources to the existing network. Despite the need for and benefits of networked solutions in a dense urban environment, the transition to a low-carbon supply mix must address some unique challenges arising from the rapidly diverging standards for existing and new buildings in Vancouver, the established built environment downtown, the distributed nature of new development, the economies of scale and resulting lumpiness of centralized solutions, the existing network technology, and constraints on available sites for centralized solutions.

3) The Company's only energy source is currently natural gas, which is used to produce steam in its only production plant at 720 Beatty Street. This plant also acts as the distribution centre for Creative Energy's existing network of more than 14 km of steam

[1] All references to the LTRP include the Fuel Switch Study ("Study").

pipes. The plant at 720 Beatty Street has provided reliable and low-cost energy for many years. However, there is a limited ability to expand this plant or cost-effectively change technologies or fuels within the current plant. Even with the addition of low-carbon energy sources in other locations, the existing gas-fired steam plant will continue to be required for peaking and back-up.

4) Given the stated GHG targets of all levels of government in Canada, the BC Energy Objectives, and the evolving standards for new development in Vancouver, the focus of resource planning at Creative Energy in recent years has been, and Creative Energy submits should be, reducing GHG emissions by fully or partially displacing the consumption of natural gas in Creative Energy's existing steam plant with low-carbon energy sources. For that reason, changes to the existing steam plant are not considered in this LTRP. Nevertheless, some changes to the existing steam plant are being contemplated for other reasons, which will also result in some improvement in plant efficiency and GHG intensity. These are expected to be the subject of a future CPCN application to the Commission.

5) This LTRP presents a plan for significant reductions in GHG emissions. In this LTRP, Creative Energy has identified the most cost-effective alternative energy source to natural gas-fired steam energy – a new (supplemental) baseload low-carbon steam plant using clean urban wood waste. This project is referred to as the Fuel Switch Project. The Fuel Switch Project does not alter the ongoing need for the existing gas-fired steam plant as both a distribution centre and as a source of firm peaking and back-up energy.

6) The Fuel Switch Project was conceived in part to support the City of Vancouver's 2011 Greenest City Action Plan and 2012 Neighbourhood Energy Strategy. The Study was completed under an MOU with the City following a Request for Expressions of Interest issued for Low-carbon Neighbourhood Energy Concepts downtown. The Study was supported with a major grant from the Green Municipal Fund, a fund financed by the Government of Canada and administered by the Federation of Canadian Municipalities. The Study builds on two previous studies conducted by Central Heat (Creative Energy's

predecessor company) and the City.

7) Although the Fuel Switch Project is one of the largest and least-cost sources of GHG reductions in Vancouver, it requires additional financial and policy support before investment risks are acceptable to Creative Energy. The investment risk reflects the large size and economies of scale in the Fuel Switch Project; low natural gas prices and carbon taxes; and insufficient load security. Existing customers are mostly on short-term contracts, reflecting the elapsed time since they originally connected. Existing customers do not currently have any formal requirements or incentives to reduce carbon beyond the carbon tax (and additional cost of offsets for provincial Public Sector Organizations), though some customers have voluntary commitments. Although the Fuel Switch Project is a cost-effective source of low-carbon energy for new development, it is too large to be absorbed by new development downtown alone, particularly near-term development. There are also challenges arising from the lack of formal mechanisms to defer carbon performance requirements for near-term developments given the lead time for the Fuel Switch Project. For new buildings under development today, there is currently no way for them to meet carbon performance requirements by committing to purchase energy from a future, to-be-built low-carbon energy plant. However, without commitments from customers, it will be extremely challenging to build the Fuel Switch Project.

8) Despite these challenges, the Fuel Switch Project remains the Company's best and preferred option for reducing GHG emissions on the network as a whole, which is the appropriate focus for long-term resource planning for the existing steam system and for this LTRP. Although the Fuel Switch Project represents the least-cost strategy for significant GHG reductions within the existing steam system, there are currently no formal requirements or financial incentives (beyond the current carbon tax) for GHG reductions by existing buildings in Vancouver. Given low embedded costs of service, low natural gas prices, and fixed carbon taxes there is a cost premium to supply low-carbon energy to existing steam customers. In the absence of enabling mechanisms that reduce the Fuel Switch Project rate impacts, the investment risks for the Fuel Switch Project are not acceptable to Creative Energy.

9) The LTRP includes an action plan that identifies the enabling mechanisms that Creative Energy intends to pursue for the next two years to advance the Fuel Switch Project. If sufficient enabling mechanisms can be secured, Creative Energy will file an Application for a Certificate of Public Convenience and Necessity for the Fuel Switch Project. In the event Creative Energy does not secure sufficient enabling mechanisms in the next two years and/or the proposed Fuel Switch Project is no longer viable for other reasons, Creative Energy proposes a contingency plan that would see it continue to rely solely on its natural gas plant for the existing steam network, and also offer individual customers the option to purchase steam produced with RNG.

10) The LTRP analyzes the external regulatory, policy and planning environment within which the Fuel Switch Project must be developed. The LTRP also includes an action plan that identifies the activities that Creative Energy intends to undertake during the next four years to advance the Fuel Switch Project. These include monitoring market conditions, consulting stakeholders, and pursuing various enabling strategies identified in the Study. While the Fuel Switch Project remains a priority of the Company, it is also time sensitive. Other strategies may be required to meet the carbon performance standards of new development if the Fuel Switch Project is delayed or becomes unfeasible. In the absence of the Fuel Switch Project, Creative Energy will consider other options for new development downtown on a case-by-case basis. These may include extensions of Creative Energy's existing Stream B TES and/or stand-alone solutions for individual nodes or sites. Stand-alone solutions are beyond the scope of this LTRP, which is limited to Creative Energy's existing Stream B utility system, including existing and committed customers in Northeast False Creek.

B. Requisite Contents for a Creative Energy Long-Term Resource Plan

11) This LTRP is in accordance with the Commission's Resource Planning Guidelines and section 44.1 of the *UCA*. In addition, Creative Energy is filing this LTRP in accordance with the following Commission directives.

> The Panel determines that Creative Energy must file a long-term resource plan pertaining to the existing steam utility no later than two years from the date of this Decision and prior to making an investment decision regarding any low carbon fuel switch that may impact the existing steam customers. The LTRP shall include information available from the fuel switch feasibility study.[2]

> Considering the arguments put forth by Creative Energy regarding the relationship of the NEFC [Northeast False Creek] to the existing utility, and that NEFC will be physically connected to the existing utility infrastructure, the Panel finds that the NEFC is not a separate utility from the existing utility. In this circumstance, the Panel is [sic] also finds that the LTRP filing previously directed for the utility includes NEFC.[3]

Not only is the Study an appropriate foundational document to and an integral part of this LTRP, but as noted above its filing with this LTRP was contemplated if not directed by the Commission.

12) The Resource Planning Guidelines state:

> Resource Planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run.[4]

This is the first LTRP filed by Creative Energy in its forty-nine year history and the first LTRP to be filed by a Stream B thermal energy utility. For that reason, the Company believes the following comments in the Resource Planning Guidelines are especially relevant to this LTRP:

> The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition.[5]

[2] RRA Decision dated June 9, 2015, p. 15
[3] NEFC Decision dated December 8, 2015, p. 71
[4] Resource Planning Guidelines, p. 1, bottom of page
[5] Resource Planning Guidelines, p. 2, last para.

13) This LTRP should be reviewed in the context of the unique circumstances of Creative Energy. Creative Energy is a small utility subject to the unique development and policy context of downtown Vancouver. Creative Energy has made significant efforts in relation to its size to pursue opportunities to reduce GHG emissions. The review of this LTRP should be about whether Creative Energy has selected the most cost-effective resource to pursue in order to reduce GHG emissions over the next 30 years. It should not be about whether the planning process of Creative Energy compares to the planning process of other much larger utilities. Those expectations should not be relevant to an LTRP filed by a small Stream B thermal energy utility**.** And to date Creative Energy is the only established small Stream B thermal energy utility to file an LTRP with the Commission. The review of this LTRP is also not intended to replace a CPCN application, which would be required if and when Creative Energy secures sufficient enabling mechanisms to proceed with the Fuel Switch Project.

14) Resource planning also often includes analysis and comparison of demand-side vs. supply-side resources. Regarding DSM and this LTRP, the expectations of the Commission are identified, at least in part, in the following comments:

> It is not necessary for Creative Energy to provide an in-depth discussion of demand-side measures in this LTRP…The LTRP must also address the potential need for and proposed timing of a comprehensive rate design (Phase II) for the existing steam utility. The requirement for this comprehensive study is subject to the pending decision on the NEFC CPCN. Further discussion of the need for a rate design as specifically relating to the Fuel Cost Adjustment methodology (Phase I) will be addressed in Section 4 of this Decision.[6]

Rate design issues and DSM issues are not considered in this LTRP because rate design issues have been previously considered by the Commission and because the Company does not provide financial incentives for energy efficiency measures among customers for reasons previously considered by the Commission.[7] Those reasons will not be repeated in this LTRP.

[6] 2015-17 RRA Decision, p. 15

[7] 2015-2017 RRA Decision, Exhibit B-2, BCUC IR 1.1.1, p.4, last paragraph.

15) For large, multi-plant systems, resource planning often includes analysis of portfolios of resource alternatives (often including a mix of demand-side and supply-side measures); this analysis often concludes with a preferred portfolio consisting of multiple (often phased) resources. Creative Energy is a small utility that currently relies on a single plant using a single fuel. This plant is required under all scenarios. Given the size of the system, magnitude of target GHG reductions, and economies of scale associated with resource alternatives, the Study considers discreet alternatives to meet the planning objectives. In addition to the preferred alternative (a supplemental baseload steam plant using clean urban wood waste), the Study considers RNG, electric steam boilers and a smaller sewer heat recovery plant serving only a new hot water network in NEFC. The analysis of a smaller sewer heat plant for NEFC is also a proxy for a comparable approach to serving other hot water extensions downtown, although additional hot water extensions are uncertain given the distributed timing and locations of new development downtown and the carbon performance requirements that must be met on a development-by-development basis. In addition to direct alternatives to the Fuel Switch Project for Creative Energy's existing steam and new hot water extensions, the Study also compares the alternatives to other low-carbon energy benchmarks including electric resistance heating, the City's own low-carbon neighbourhood energy utility in Southeast False Creek, and a range of recent on-site (Stream A) utilities registered with the Commission.

16) The requisite contents for a long-term resource plan are also established by section 44.1(2) of the *UCA*, which will be addressed in Section K. Creative Energy submits that this LTRP meets the requirements of the *UCA* and the also the energy objectives in the *CEA*, which will be addressed in the following Section C.

C. Long-Term Planning Objectives

17) The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives. Creative Energy's existing plant has provided secure, reliable and cost-effective energy for many years. With modest upgrades, the existing plant can continue to meet existing and known customer needs indefinitely. However, sole reliance on natural gas is no longer congruent with British Columbia's energy objectives or with GHG targets and policies of other levels of government. For this reason, Creative Energy believes that reducing GHG emissions is the most appropriate focus for this LTRP. This will also be a prerequisite for adding new customers under Vancouver's new Zero Emission Building policy.

18) Section 44.1(8) of the *UCA* requires the Commission to consider certain factors when accepting a utility's long-term resource plan, including:

- Energy objectives as defined in the *CEA*, and
- The extent to which the long-term resource plan is consistent with the applicable requirements under sections 6 and 19 of the *CEA*.

19) The *CEA* contains a set of sixteen specific energy objectives – BC Energy Objectives. The BC Energy Objectives relevant to this LTRP are as follows:

- To use and foster the development … of clean or renewable resources (section 2(d))
- To reduce greenhouse gas emissions (section 2(g))
- To encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions (section 2(h))
- To encourage communities to reduce greenhouse gas emissions… (section 2(i))
- To reduce waste by encouraging the use of waste heat, biogas and biomass (section 2(j))

The objective of this LTRP – to reduce GHG emissions - by developing the Fuel Switch Project is aligned with these Provincial objectives. There are other Provincial objectives found in the *CEA*; however, such objectives are either not relevant, such as objectives specific to BC Hydro, or are consistent with the Provincial objectives listed above.

D. Planning Environment Relevant to GHG Emissions

20) In addition to the BC Energy Objectives, Creative Energy must also consider the unique market circumstances of thermal energy systems, Creative Energy and the City of Vancouver.

21) Creative Energy is a small utility. The existing steam network and gas-fired steam plant are very reliable and low cost. The bulk of existing assets have significant remaining life, and a majority of existing customers are on short-term contracts. Creative Energy must compete with conventional energy sources and suppliers for existing customers and buildings. Although market research suggests some voluntary demand and willingness to pay a premium for low-carbon energy among large commercial buildings, the depth and strength of these commitments would need to be confirmed through new long-term customer contracts.

22) In contrast to the situation for existing buildings, the City of Vancouver has established high carbon performance standards for new development. These standards are expected to increase rapidly over time and will soon make it difficult to connect new customers to the existing steam network (including hot water extensions to the steam network) without adding networked or on-site low-carbon energy sources. As of today, new development has to demonstrate compliance with these carbon requirements at the time of individual development approvals, hindering Creative Energy's ability to (for example) pool the commitments from multiple new development projects and leverage them to support the Fuel Switch Project.

23) Creative Energy's existing production plant and network are based on steam technology. Two steam-to-hot water converter stations have been installed to support a new hot water network for NEFC. Hot water is also being contemplated for other major extensions, where feasible. However, given its current age and condition, the costs of converting the existing steam network to hot water far outweigh the benefits, including efficiency benefits. A major new investment to transition from steam to hot water would also require additional load security relative to the status quo. In the long-term, an opportunistic and phased conversion of the steam network to hot water is contemplated, but this is outside the scope of the current LTRP, which focusses on ways to reduce GHG emissions given the existing steam network. There are a limited number of technologies and fuels available to produce low-carbon steam. There are some additional alternatives available for producing low-carbon hot water, but these would be limited to areas with hot water networks (e.g., NEFC). The availability and cost of these hot water alternatives is also dependent on the specific resources in or near individual hot water networks.

24) All levels of government have aggressive targets for GHG reductions. Current policies do not yet match reduction targets. But all governments are actively exploring additional policies to achieve their targets. Some of these policies are economy-wide and others sector-specific. The most relevant economy-wide policies for this LTRP involve carbon taxes or prices. B.C. has not made any formal commitments to increase the carbon tax but the federal government has introduced the concept of a minimum national floor by 2022 that would exceed B.C.'s current carbon tax. This floor would not be adequate to meet national targets but is intended as a significant first step. The federal government has also contemplated a renewable standard for heating fuels, which could have similar effects as a carbon tax but would be limited to the heating sector.

25) The federal government has established internal targets for carbon reductions and renewable energy supply within its operations. Creative Energy already serves several federal facilities, and there are other major federal facilities downtown that could be connected to the Fuel Switch Project.

26) About 12% of Creative Energy's existing load consists of provincial Public Service Organizations (PSOs). PSOs are required to source low-carbon energy or purchase offsets (over and above the carbon tax) for residual GHG emissions under B.C.'s carbon neutral government commitments. As a result, PSOs have additional financial incentives to purchase low-carbon energy.

27) In 2015, the Province purchased nearly 625,000 tonnes of GHG offsets to meet these carbon neutral commitments. The Province expects to require over 650,000 tonnes per year of new offsets by 2021 (as current contracts expire). The Province has expressed some interest in purchasing offsets arising from GHG reductions from the Fuel Switch Project for non-governmental customers.

28) There are several City-controlled buildings connected to the existing Creative Energy system. Like federal and provincial governments, the City of Vancouver has commitments to reduce GHG emissions and increase renewable energy supply within its own operations.

29) There are currently no formal federal, provincial or municipal incentives for large-scale renewable heat projects. However, in the 2016 budget the federal government announced investments of $11.9 billion in public transit, green infrastructure and social infrastructure. The federal government's Fall 2016 Economic Statement proposed an additional $81 billion through to 2028 in public transit, green and social infrastructure, transportation infrastructure that supports trade, and rural and northern communities. The federal government also announced it will establish a new Canada Infrastructure Bank, an arm's-length organization intended to increase investment in growth-oriented infrastructure. And the federal government also announced a $2 billion Low Carbon Economy Fund, which is expected to begin in 2017. This fund is intended to support concrete measures that generate new, incremental GHG reductions while considering cost-effectiveness. Taking all previous and recent announcements together, the federal government has committed more than $180 billion in infrastructure funding to 2028. The design of these programs is still in development and more information on funding model

and eligible projects is expected in Fall 2017. However, these programs could provide sources of funds for large-scale renewable heating projects such as the Fuel Switch Project.

E. Load Forecast

30) As discussed in Section B, the Commission required that Creative Energy file an LTRP pertaining to the existing steam utility, and it also directed that this LTRP include NEFC, which the Commission observed is connected to the existing steam utility.

31) Creative Energy's existing customer base is relatively stable, reflecting a long history of high reliability and low costs of service. Given the utility size and customer numbers, changes in load tend to be lumpy and influenced by very site-specific conditions. In recent years, efficiency upgrades and other changes in individual customer buildings have been largely offset by new customer additions. Existing steam sales are approximately 385,000 MWh per year. Including network losses, this equates to a steam production of approximately 420,000 MWh per year under average weather.

32) One of the benefits of thermal networks is economies of scale. Other benefits include economies of integration (load diversity giving rise to better utilization of capacity), diversification of technologies and fuels with scale, and the ability to tap sources of low-carbon heating and/or cooling not available or suitable at individual building sites (including sources of waste energy). There are considerable economies of scale in the Fuel Switch Project arising both from high initial project costs (i.e., the need for a new site and interconnection) and economies of scale in equipment and operations (e.g., plant staffing). While scale has benefits to consumers, it also poses implementation challenges given the current market and policy environment.

33) When the Study commenced, the City and Creative Energy had contemplated franchise agreements to support the development of new hot water networks and low-carbon

energy sources for the NEFC (including Chinatown) and South Downtown neighbourhoods. The Study was to evaluate the effect of additional load on the economics of the Fuel Switch Project, as well as the benefits of the Fuel Switch Project for new neighbourhoods with formal carbon performance standards. By 2030, the total demand in NEFC and South Downtown was expected to reach 85,400 MWh per year. The total committed demand in NEFC is now approximately 15,000 MWh. Further customer connections in NEFC and South Downtown are uncertain.

34) Towards the end of the Study, the Commission denied the Neighbourhood Energy Agreement (NEA) between Creative Energy and the City for NEFC, which was intended as the template for a similar agreement in South Downtown. The NEA would have transferred carbon performance requirements from individual development sites to the neighbourhood as a whole. The NEA would also have decoupled the timing of low-carbon resource additions from individual developments, allowing Creative Energy to pursue the optimum sizing and timing of solutions at a neighbourhood scale. City connection policies, in turn, would have provided additional security of future loads to help advance a larger project sooner. Although the Commission approved the network solution for NEFC, the lack of franchise agreements has created uncertainty over future loads. About 30% of the floor area in NEFC is now connected or committed. But there is no agreement with the City for Creative Energy to meet carbon performance standards for committed customers, and there is no security of additional loads in the neighbourhood. In the absence of an agreement or other policy changes, carbon performance standards for additional development will need to be met on a development-by-development basis, which may or may not include connection to the existing steam or hot water networks.

35) Over the course of the Study, Creative Energy identified many additional infill developments and potential new nodes that could be connected to the core besides NEFC and South Downtown. These include major nodes of new development in the West End, Georgia Corridor and Downtown Eastside. The City-owned neighbourhood energy utility in Southeast False Creek (SEFC) is also a potential customer for the Fuel Switch

Project. These additional loads are not included in the base case analysis, but they are considered in sensitivity analyses and as one of the enabling mechanisms for the Fuel Switch Project. The Fuel Switch Project is a competitive source of low-carbon energy for new development with formal carbon performance requirements. Connection of new development can help minimize initial investment risks and mitigate rate impacts for existing customers. However, given the initial size of the project and extent of existing networks there would need to be additional policy mechanisms to secure sufficient near-term and/or long-term development for the Fuel Switch. For near-term development, there would also be a need for explicit mechanisms to address differences in the lead time of the Fuel Switch Project and the timelines for individual development approvals by the City.

F. Natural Gas Price Forecasts and Carbon Price Forecasts

36) The point of reference for existing steam customers (including existing NEFC customers in the absence of an approved Neighbourhood Energy Agreement) is the cost of gas-fired steam from Creative Energy's existing steam plant. This plant is sunk and will be required for ongoing peaking and back-up in all scenarios. As a result, if Creative Energy produces low-carbon steam, the avoided cost is natural gas fuel and carbon taxes.

37) The avoided cost of gas-fired steam is based on third party forecasts of natural gas commodity prices (Sproule), expected FortisBC delivery costs (assuming escalation at CPI), and expected carbon taxes. Future natural gas and carbon prices are very uncertain, and the Study includes analysis of many possible alternate scenarios. In addition to the future level of carbon taxes, another key uncertainty is the GHG emission factor for various fuels. For example, B.C.'s Climate Leadership Team has recommended that upstream emissions should be included in the carbon intensity of natural gas. Estimates of upstream emissions vary widely but even the low estimates would increase the effect of current carbon taxes on natural gas prices. And regardless of whether they are included in carbon taxes, consideration of upstream emissions would greatly increase the GHG reduction benefits of the Fuel Switch Project.

38) In addition to fuel prices and carbon prices, the other determinant of the avoided costs for reducing use of gas-fired steam is the efficiency of the steam plant. The average annual efficiency of the existing steam plant (total steam produced at the plant gate divided by total natural gas input) is approximately 85%. However, the Fuel Switch Project would displace baseload production and the plant efficiency is slightly higher in baseload conditions – approximately 86%.

39) Under the base case assumptions for natural gas prices, carbon taxes and baseload plant efficiency in the Study, the levelized cost of gas-fired steam at the plant gate over the analysis period is $42 / MWh. This reflects the sunk cost of the existing steam plant. The avoided costs of natural gas-fired heat would be higher if additional generating capacity is required (e.g., for new development). The avoided cost of gas-fired steam has declined to $35 / MWh under more recent natural gas price forecasts. However, proposed increases in carbon taxes or a renewable fuel standard for heating fuels would increase avoided costs. There is a very wide range around avoided costs for gas-fired steam based on alternate scenarios for future natural gas and carbon prices.

40) The investment risk for the Fuel Switch Project is represented as the difference in the present value of the cost of gas-fired energy under the status quo, and the present value of the cost of energy from the Fuel Switch Project. This financial gap represents the outstanding investment risk in the absence of other enabling mechanisms. The financial gap is not intended to represent value to customers or societal benefits of GHG reductions. For example, PSOs, which make up about 12% of existing steam loads, also avoid an additional cost for offsets (which are purchased directly by each PSO). At current emission factors for natural gas and carbon taxes, the cost of offsets currently adds about $9 / MWh to the cost of steam for PSOs. Similarly, some customers have expressed some interest in paying a premium for low-carbon energy. Some of these customers have corporate commitments for GHG reductions. Others are interested in recertifying their buildings to attract tenants with corporate commitments. And some customers simply see value from reducing exposure to volatile natural gas prices and/or

highly uncertain future carbon taxes or policies. There are also other potential revenue sources for the project including the sale of offsets or renewable energy credits. And the gap can be further reduced through other project optimizations, cost reductions and grants, and/or by allocating more output to new developments with formal carbon performance standards and higher avoided costs. These represent mechanisms to reduce the financial gap and investment risks to an acceptable level. But these will need to be confirmed through formal contracts or agreements. This is the focus on the action plan, which is discussed in Section I.

G. Resource Options

41) The LTRP builds on several previous studies for the City and Creative Energy's predecessor (Central Heat) which helped to establish both the magnitude of target GHG reductions and resource options.

42) Creative Energy explored a number of options to meet the planning objectives, namely GHG reductions. These do not include utility-sponsored demand-side programs for reasons discussed previously. However, the Study does compare the magnitude and costs of GHG reductions from Creative Energy's supply-side alternatives against some recent studies of the potential magnitude and cost of GHG reductions from major building retrofits. The Study also considers other external benchmarks of retail rates, including benchmarks for on-site low-carbon energy sources or systems.

43) The Study contains a detailed description of the Fuel Switch Project including proposed technology, sizing, site, building concept (including a rooftop farm), and interconnection routing. The base case costing is conservative reflecting cost and performance estimates developed by experts and informed by requests for information from technology vendors and potential fuel suppliers. The target sizing for the base case analysis (a new 65 MW baseload low-carbon plant) was informed by previous studies, updated analysis of Creative Energy's load duration curve, consideration of likely new loads at the time the Study commenced, upfront fixed project costs (site, building and interconnection, which

result in economies of scale), and consideration of GHG reduction targets from various levels of government. Sensitivity analysis included some consideration of possible phasing of the project, as well as other design optimizations. Considerable analysis was also conducted on possible enabling mechanisms for the project, including alternate load scenarios, grants, offset / credit sales, and property tax treatment.

44) Estimated property taxes alone represent about 12% of the cost of this project and nearly a third of the financial gap for the project. This is discretionary project for existing customers, who will continue to pay property taxes for the existing system. British Columbia is also unique in having a utility classification for property taxation, and the utility mill rate is the highest mill rate in Vancouver, three times higher than the business rate (which is the next best use of the target site) and higher even than the rate for large industrial uses. The bulk of property taxes associated with this project would be entirely incremental and would not exist in the absence of this project. The effect of the high utility mill rate is further compounded by high land values and higher cost of aesthetic treatment of plants required in dense urban areas.

45) Rate impacts for existing buildings can also be mitigated by reducing and/or phasing the GHG reductions for existing buildings. However, given economies of scale for the Fuel Switch Project this would also require securing other customers (with carbon performance requirements or demand) or other sources of revenue in the interim.

46) A major driver of the cost premium for existing customers is the outlook for natural gas and carbon prices, which are a flow through to existing customers. Despite recent stability, natural gas has exhibited very high levels of volatility in the past. More important than commodity prices for natural gas are future carbon taxes or policies.

47) The Study considers a range of project alternatives, including alternatives for GHG reductions for the existing steam system and alternatives to provide incremental GHG reductions for new loads. A sewer heat plant has been developed by the City for SEFC and there is a potential to develop a similar plant for NEFC. This alternative is

considered representative of smaller-scale solutions for new hot water networks. A new sewer heat plant cannot serve existing steam customers without additional changes in distribution networks and customer interfaces. In addition to a smaller-scale sewer heat plant for NEFC, the Study also compares the cost of service for the Fuel Switch Project to the cost of an incremental expansion of sewer heat in SEFC (which reflects the incremental cost of installing additional heat pumps in an existing facility and incremental electricity costs). The Study also compares retail rates with and without the Fuel Switch Project to a range of external benchmarks such as electric resistance heating, SEFC, and recent on-site TES.

48) Rate impacts for existing customers are based on status quo energy supply, which is possible in the absence of further regulation of GHG emissions in existing buildings. All low-carbon alternatives for existing customers have some premium over conventional energy supply. New development has a different baseline because new development must demonstrate in the design phase (i.e., through modelling) that it can in theory meet carbon performance requirements (via modelled envelope and equipment efficiency and sources of energy) to secure development approvals.

49) Table 1 below provides a summary of various alternatives and scenarios for GHG reductions, which are discussed in much more detail in the Study. Table 2 provides a summary of various retail rate benchmarks.

Table 1: Summary of Resource Options for GHG reductions (Selected Scenarios)

	Levelized Production Cost* $/MWh	Levelized Bill Impact	GHG Reductions for Existing Steam Customers* tonnes / year (% reductions)	Additional Comments
Status Quo				
Gas Fired Steam – Base Case Assumptions for Gas and Carbon	$34 – 35	N/A	N/A	• Reflects range of gas price forecasts between January and December 2016 and current carbon taxes ($30 / tonne) escalated at CPI. • Low avoided cost reflects in part sunk costs of existing steam plant.
Gas Fired Steam – Carbon Tax Proposal from B.C. Climate Leadership Team	$60 – 62	+45%	N/A	• Assumes no change in gas commodity costs but annual increases in carbon taxes as proposed by Climate Leadership Team. • Assumes no future change in carbon intensity of natural gas (i.e., to reflect upstream emissions). • Bill impact reflects change in total cost of service with 100% gas-fired steam.
Low-Carbon Alternatives				
Fuel Switch Project – Base Case	$71	+43%	67,500 (75%)	• Assumes full property taxes on land, building and interconnection at utility mill rate, and no interconnection optimizations. • Excludes savings to PSOs from avoided purchase of offsets. Net bill impacts for PSOs reduced to 27% before any enabling mechanisms. • Assumes about 17% of the project is allocated to new customers with formal carbon performance requirements. Total GHG reductions from project including new customers is 81,500 tonnes/year. • Bill impact reflects change in total cost of service with 75% biomass-fired steam and 25% gas-fired steam using base gas and carbon assumptions.
Fuel Switch Project – Smaller Plant	$79	+38%	48,500 (54%)	• Smaller plant has higher unit cost of energy and GHG reductions. • Bill impacts reduced because of lower GHG savings. • Smaller plant could still be expanded in future.
Fuel Switch Project – Base Case Plant Size + Basic City Enabling Mechanisms	$62	+29%	59,900 (67%)	• Reflects optimizations of the interconnection cost, elimination of property taxes on interconnection, and reduction of property taxes on site to business rate. • Lower bill impacts also reflects lower GHG reductions for existing customers after additional sales to SEFC.

	Levelized Production Cost* $/MWh	Levelized Bill Impact	GHG Reductions for Existing Steam Customers* tonnes / year (% reductions)	Additional Comments
Fuel Switch Project – Basic City Enabling Mechanisms + Reduced GHG Savings for Existing Customers	$62	+18%	43,300 (45%)	• Reflects basic city enabling mechanisms in previous scenario, fewer GHG reductions allocated to existing steam customers and increased sales to new development.
Fuel Switch Project – Basic City Enabling Mechanisms + Reduced GHG Savings for Existing Customers + $50 million Grant	$52	+11%	43,300 (45%)	• Same scenario as above plus grant from other levels of government.
Electric Steam Boiler Plant	$127	+109%	67,500 (75%)	• Reflects only variable cost of electric steam boilers. • Would also require a new site, building, interconnection, new boilers, and ancillary equipment.
Sewer Heat Plant – NEFC Only (Full Build Out)	$113 – 125	N/A	N/A	• Can only supply new hot water loads in NEFC. Does not affect existing steam loads outside NEFC. • Costing based on full neighbourhood and carbon outcomes comparable to SEFC. • Assumes plant is implemented at ~50% build out.
Incremental Sewer Heat Pump for SEFC	$72 – 76	N/A	N/A	• Not a Creative Energy resource alternative but alternative to purchases of Fuel Switch energy by SEFC • Reflects only incremental costs of a second heat pump and additional electricity fuel costs. Building and ancillary infrastructure already in place. • Purchases by SEFC would decrease initial energy / GHG reductions available to existing steam customers. Further reductions for existing customers possible by advancing second heat pump in SEFC or other low-carbon energy sources.

	Levelized Production Cost* $/MWh	Levelized Bill Impact	GHG Reductions for Existing Steam Customers* tonnes / year (% reductions)	Additional Comments
Renewable Natural Gas (Existing Plant)	$65 - 90	35 – 65%	67,500 (75%)	• There is no publicly available information on the marginal production cost of RNG. • Analysis assumes marginal cost ranging from $12/GJ (fixed) to $14.5 /GJ (escalated at 2% per year) • Bill impacts based on acquiring enough RNG to achieve same GHG reductions as Fuel Switch Project Base Case. • RNG has higher unit cost of energy and unit cost of GHG reductions, but does not require new capital investment and GHG reductions could be phased. • Uncertainty over available volume of RNG. To meet the same target reductions, Creative Energy would require approximately four times FortisBC's existing supply of RNG for this one project alone.

* For off-site steam options this includes delivery costs to Beatty Street Plant, which acts as the distribution centre for the system.

**For this calculation, Core Steam Customers are defined as existing steam customers excluding committed loads in NEFC, which are considered part of new development areas with formal carbon performance requirements in the Study.

Table 2: Retail Rate Benchmarks (Levelized over 2020 – 2040 Analysis Period)

	Levelized Retail Rate $/MWh	
Creative Energy Status Quo Steam Service	$77	• Base case gas and carbon prices. • No change in GHG emissions
Creative Energy Status Quo Steam Service – PSOs (including offsets)	$86	• No change in GHG emissions • Reflects additional cost of offsets for PSOs, assuming offsets escalate at inflation only.
Creative Energy Steam Service with Fuel Switch (Basic City Enabling Mechanisms)	$99	• Reflects 67% reduction in GHG emissions for existing customers.
Creative Energy Steam Service with Fuel Switch (Basic City Enabling Mechanisms and Lower GHG Reduction Targets for Existing Customers)	$91	• Same cost assumptions as previous scenario but 45% reductions for existing steam customers with more of project allocated to new development.
Creative Energy Hot Water Service in NEFC – Gas Only	$90 - 93	• Assumes full build out. • No low-carbon energy, which is not a viable option for new development.
Creative Energy Hot Water Service in NEFC – Local Sewer Heat Plant	$147-151	• Assumes all load is captured and carbon performance standards are met with a local sewer heat plant, similar to SEFC.
Creative Energy Hot Water Service in NEFC – Fuel Switch	$106 - 109	• Before any enabling mechanisms or cost reductions for the Fuel Switch Project.
Residential Electric Heat	$174	• Cost of electricity only assuming electric resistance baseload and/or water tanks at 100% efficiency • Treated as zero carbon energy but uncertainty in current and future GHG emission intensity. • Forecast assumes retail electricity prices increase only 2 – 3% per year for remainder of analysis period beyond current rate plant.
SEFC	$138	• Based on current build out assumptions and expansion of existing sewer heat plant.
Other Recent On-site TES	$154 – 187	• Representative sample of approved rates for onsite TES. Not all of these achieve the target GHG reductions of the Fuel Switch Project. • Actual rates are not fixed and may vary with flow-through of changes in fuel costs. Range reflects system owner forecasts of future gas and electricity prices. • Many on-site TES received substantial capital contributions from property developers, so rates are often not reflective of all lifecycle costs.

H. Stakeholder Engagement

50) This LTRP has been informed by preliminary stakeholder consultations, as well as information from other relevant consultation processes conducted by the City. Creative Energy submits that the form and level of consultation is appropriate for the nature of the Study and current status of the Fuel Switch Project. Creative Energy is currently focused on enabling mechanisms to mitigate investment risks and any financial gap. Once more progress on these has been made, further consultation will be conducted to advance the project design, secure customer commitments, prepare all relevant permit applications (e.g., air quality permit, development permit and building permit), and to prepare a CPCN application. If Creative Energy is not successful in securing sufficient enabling tools, the focus of additional consultations will be on incremental solutions for new development and other smaller (distributed) and phased solutions for existing customers if and when required as a result of changes in carbon taxes or other policies.

51) The Study contains additional information on consultations to date. Some highlights:

- A preliminary workshop with Commission staff at the beginning of the study;
- Requests for information from equipment vendors and fuel suppliers;
- Regular interaction and support from City staff;
- City consultations on the Greenest City Action Plan, District Energy Strategy, Renewable City Strategy, Green Building Policy, and various neighbourhood consultation processes;
- In-depth stakeholder interviews by a public opinion research company;
- One-on-one meetings with more than 50 individuals or groups including politicians, customers, community stakeholders and institutions; and
- Ongoing discussions with federal and provincial departments related to carbon policies, funding programs, offset sales and green procurement processes for government operations.

I. Action Plan

52) The Fuel Switch Project is currently the least-cost source of centralized low-carbon energy for Creative Energy. However, there is no legislative requirement for Creative Energy or existing customers to procure low-carbon energy in the face of a large price differential with existing gas-fired energy. Creative Energy will require additional enabling mechanisms prior to a final investment decision in the Fuel Switch Project. The project will also require a CPCN from the Commission.

53) The action plan describes the activities that Creative Energy intends to pursue to enable the Fuel Switch Project. Given the time-sensitive nature of the Fuel Switch Project, the focus of this action plan is on securing various enabling mechanisms within the next two years. Once secured, the remainder of the action plan would involve preparing a CPCN Application and completing other project development tasks necessary to commence construction within four years.

54) There are a variety of enabling mechanisms to secure an investment in the Fuel Switch. These are described in more detail in Section 14 of the Study. Some enabling mechanisms would reduce project costs and rate impacts under base natural gas prices and carbon taxes for existing customers. These include mechanisms to reduce the cost of the interconnection, to rationalize property taxes, to defer land costs and residual property taxes (based on actual gas and carbon prices), and to reduce capital or other operating costs (including external grants). Other mechanisms seek to secure additional revenues. These include new long-term contracts with existing customers willing to pay a premium for low-carbon energy, sales of external offsets, and sales to new customers with formal carbon performance requirements. The latter could include sales to the City's own neighbourhood energy utility in SEFC, which requires additional low-carbon energy to meet growing loads, and the transfer of carbon reduction credits to other developments or neighbourhood energy systems not directly connected to the steam system. Given the cost-effectiveness of the Fuel Switch Project, sales to new customers would reduce the financial gap, but would also reduce the GHG reductions allocated to existing customers.

However, this would help to secure an initial investment in this cost-effective but time sensitive project, and this does not preclude further investments in low-carbon energy, if and when additional GHG reductions are desired or required by existing steam customers.

55) A key element of the action plan is an enabling agreement with the City of Vancouver. This enabling agreement is expected to confirm the availability, terms and conditions for the proposed City-owned site of the Fuel Switch Project, and also any other enabling mechanisms the City will contribute towards the project. This could include commitments to coordinate the installation of the interconnection with other City infrastructure projects, property tax relief, commitments of City-controlled loads, and a purchase agreement for SEFC or other new City-led thermal energy systems.

56) A formal enabling agreement with the City will support ongoing efforts to secure grants from senior levels of government, as well as an agreement for the temporary sale of offsets to the Province. Creative Energy continues to monitor the formation of new federal funding programs. And Creative has already submitted a Project Information Document to the Province as a first step to securing an agreement for the sale of offsets.

57) As a final step in the action plan, Creative Energy intends to seek long-term commitments from existing customers to purchase low-carbon energy. Given the current magnitude of the financial gap, the lack of formal policies for existing buildings, and the time and effort required for a voluntary subscription process, Creative Energy does not anticipate it will embark on the voluntary subscription process until completing an enabling agreement with the City and confirming the availability of other enabling tools. Confirmation of provincial and federal load commitments are also expected to support the subscription process for private sector customers.

58) In addition to activities related to securing the above enabling mechanisms and strategies, Creative Energy will continue to monitor the external planning environment that may affect existing customer demand for GHG reductions and the economics of the Fuel

Switch Project, including the outlook for natural gas prices and carbon taxes; the availability and price of clean urban wood waste; available technology costs and performance; available sites for a new low-carbon plant; the outlook for interest rates; changes in carbon or other policies that may affect the viability of the Fuel Switch Project or other low-carbon alternatives; and opportunities to secure major new developments with carbon performance standards.

59) In the absence of sufficient enabling mechanisms within this time frame, the Fuel Switch Project and indeed any centralized solution to reducing GHG emissions and increasing renewable energy in downtown Vancouver is likely to become difficult as a result of growing constrains on available land, rapidly rising land costs, lost opportunities to secure major near-term new developments with higher carbon standards, external competition for local wood waste, and rising interest rates, among other factors. If sufficient enabling mechanisms cannot be secured or the Fuel Switch Project becomes unfeasible for other reasons, Creative Energy will continue to focus on alternative solutions to serve new development with formal carbon performance requirements and will also consider offering existing customers the option to purchase steam produced with higher cost RNG to meet voluntary commitments or future requirements for GHG reductions in existing buildings.

J. Order Sought and Recommended Regulatory Process

60) Creative Energy submits that this LTRP meets the requirements of the *UCA* and seeks the Commission accept this LTRP as being in the public interest pursuant to section 44.1(6) of the *UCA*. Under section 44.1(5), the Commission may establish a process to review long-term resource plans. In Creative Energy's view, the Commission is not obligated to establish any process. Creative Energy does not object to a process that reflects the size of Creative Energy and the unique nature and context of this LTRP. However, if the Commission does determine that a review process is appropriate, Creative Energy recommends that the Commission first establish the appropriate scope of the review to

inform any determination on process.

61) Creative Energy is not seeking any determination under section 44.1(9) of the *UCA*, or any approval of specific capital costs or rate changes as part of this LTRP submission. In the next RRA filing, the Company expects to seek recovery of both incurred and future costs of this LTRP, including the costs of the Study, as part of the approved Third Party Regulatory Costs Deferral Account. The incurred costs include costs that pre-date the approval of the Third Party Regulatory Costs Deferral Account and, in part, for that reason were not forecast in accordance with the 2016-2017 RRA Decision. However, as noted above, the filing of the Study was contemplated, if not directed, to be filed as part of the LTRP.

62) Creative Energy expects to submit a separate application for upgrades to the existing steam plant, which are outside the scope of this LTRP. Creative Energy also expects to submit applications for a CPCN and/or rates prior to any investment in low-carbon energy source(s), or for major network extensions/changes. Given the current market conditions, policy gaps and regulatory constraints for larger thermal networks and low-carbon energy sources, Creative Energy is uncertain if or when such applications will be required or what form they will take.

63) Should the Commission still wish to initiate a process to review Creative Energy's LTRP submission, Creative Energy submits a streamlined review process would likely be most appropriate given the scale and nature of this utility and LTRP.

64) Regardless of the Commission decision and process, Creative Energy intends to continue to monitor the policy environment and market conditions for low-carbon energy sources and networks, and to continue to pursue enabling mechanisms for the larger Fuel Switch Project. Creative Energy also intends to continue to consult stakeholders on low-carbon energy options. Given new green building standards and uncertainty in the larger Fuel Switch Project, Creative Energy will also consider alternatives to the Fuel Switch for new customers, in collaboration with those customers, on a case-by-case basis. This may

include various combinations of extensions of the existing steam network, new hot water extensions and/or stand-alone low-carbon energy sources for individual sites or nodes, where feasible,

K. Commission Considerations for Accepting a Long-Term Resource Plan

65) The UCA includes the requisite contents for a public utility's LTRP, as set out in section 44.1(2) of the Act. However, as noted in its guidelines for resource planning, the Commission will review resource plans in the context of the unique circumstances of the utility in question. In the case of Creative Energy some of the unique circumstances include the service being provided (thermal energy, for which there is no precedent for LTRPs filed with the Commission), the size of utility, the nature of the customer base (a limited number of large buildings with very unique ownership, use and technical characteristics), geographic context (dense urban core, older buildings with dispersed in-fill development), market context (competition for thermal energy supply, very different carbon standards for existing buildings and new development, low gas and carbon price outlook, lack of policy support for large investments), and the form / age / conditions of existing assets (relatively young system, steam network, single plant, limited space/sites for new plant and alternative technologies).

66) Based on unique circumstances and prior determinations by the Commission, Creative Energy submits that the subsections applicable to the nature of the service provided by Creative Energy are 44.1(2)(c) and 44.1(2)(d) as follows:

Section of the UCA	Requirement Defined in the UCA	Section of LTRP Addressing Requirement
44.1(2)(a)	An estimate of the demand for energy the public utility would expect to serve if he public utility does not take new demand-side measures during the period addressed by the plan	For reasons previously considered by the Commission, Creative Energy does not have utility-sponsored DSM programs.
44.1(2)(b)	A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand side measures	For reasons previously considered by the Commission, Creative Energy does not have

		utility-sponsored DSM programs.
44.1(2)(c)	An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures	An estimate of demand for energy is found in Section E of this filing and also Section 8 of the Study.
44.1(2)(d)	A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c)	The Study contains a detailed description of the preferred alternative for reducing GHG emissions for existing steam customers but Creative Energy does not intend to construct the facility without additional enabling mechanisms or other changes in policy and market conditions to support the investment in low-carbon energy for existing customers.
44.1(2)(e)	Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to paragraph (c)	Creative Energy does not intend to purchase energy from other persons, with the exception of fuel sources for the production of thermal energy. Creative Energy will consider the purchase of RNG for existing customers that wish to purchase steam produced with RNG as a contingency plan in the event Creative Energy cannot secure sufficient enabling mechanisms or the lower cost Fuel Switch Project becomes unfeasible for other reasons.
44.1(2)(f)	An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures	For reasons previously considered by the Commission, Creative Energy does not have utility-sponsored DSM programs.
44.1(2)(g)	Any other information required by the Commission	Commission directives are referred to in Section B.

67) Creative Energy applies pursuant to section 44.1(3) of the *UCA* for an order to exempt Creative Energy from the requirement to include in the long-term resource plan information referred to in paragraphs 44.1(2)(a), 44.1(2)(b), 44.1(2)(e) and 44.1(2)(f) of the *UCA*.

List of Appendices

A LOW-CARBON LEGACY

FOR DOWNTOWN VANCOUVER

FINAL FEASIBILITY REPORT FOR THE CREATIVE ENERGY FUEL SWITCH

MARCH 17, 2017

PREPARED FOR:
Creative Energy Platforms **Canada Ltd.**

CO-FUNDED BY:
The Federation of Canadian Municipalities
The City of Vancouver

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CREATIVENERGY

RESHAPE STRATEGIES

STATEMENT OF LIMITATIONS

This report has been prepared by Reshape Infrastructure Strategies ("Reshape") and our partners for the exclusive use and benefit of Creative Energy. This is a feasibility report based on preliminary design and representative cost and performance information. Final costs and performance must be confirmed in the detailed design and vendor selection phases. This document represents the best professional judgment of Reshape and our partners, 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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GREEN MUNICIPAL FUND SUPPORT

The preparation of this feasibility study was carried out with assistance from the Green Municipal Fund, a Fund financed by the Government of Canada and administered by the Federation of Canadian Municipalities. Not withstanding this support, the views expressed are the views of the authors, and the Federation of Canadian Municipalities and the Government of Canada accept no responsibility for them.

PHOTO CREDITS

Unless otherwise noted, all photos were provided by Creative Energy, Reshape, or sub-consultants and advisors on this project.

ACKNOWLEDGEMENTS

Study funding and in-kind support was provided by:

CREATIVENERGY

FCM FEDERATION OF CANADIAN MUNICIPALITIES FÉDÉRATION CANADIENNE DES MUNICIPALITÉS

CITY OF VANCOUVER

This study was led by Reshape Infrastructure Strategies with assistance from the following firms:

FOSDICK & HILMER CONSULTING ENGINEERS	*Technical advisors*
HENRIQUEZ PARTNERS ARCHITECTS	*Advisors in site selection and site concept*
BIG	*Preliminary site concept architecture*
westbank	*Building cost estimates, implementation issues*
ICON WEST CONSTRUCTION	*Building cost estimates*
FRESH · LOCAL · RESPONSIBLE · IUFA FARMS	*Rooftop farm concept information*
WSP | LEVELTON	*Air quality screening assessment*
Ipsos Public Affairs	*In-depth stakeholder interviews*
KORNFELD LLP LAWYERS	*Legal analysis and review*
DIALOG	*Infographics*
kwl KERR WOOD LEIDAL consulting engineers	*Steam to hot water conversion analysis*
bunt & associates TRANSPORTATION PLANNERS AND ENGINEERS	*Transportation review*

EXECUTIVE SUMMARY

This report summarizes a two-year feasibility study for the Creative Energy Fuel Switch, a large low-carbon energy project for downtown Vancouver. The Fuel Switch is one of the largest single opportunities to reduce GHG emissions and increase renewable energy in Vancouver. This opportunity exists because of a shared heating network established in the late 1960s by a visionary group of local engineers and entrepreneurs to provide a cost-effective and reliable heating service while also addressing local air quality problems of the day. Today, this network serves more than 200 buildings downtown, with a combined floor area of over 4.2 million square metres, from a single heating plant located at the corner of Beatty and Georgia Streets. This is one of the largest district energy systems in Canada in terms of connected floor area. Customers include landmarks such as BC Place, St. Paul's Hospital, and the Queen Elizabeth Theatre, together with many hotels, office buildings and residential stratas. Federal, provincial and municipal buildings represent about 17% of energy sales. There are also many other existing buildings and new developments downtown not yet connected to Creative Energy that could benefit from connection to low-carbon district energy.

This feasibility study was completed for Creative Energy under a Memorandum of Understanding (MOU) with the City of Vancouver after Creative Energy was selected by the City as its preferred proponent in its 2013 Request for Expressions of Interest (RFEOI) for Neighbourhood Energy Concepts for Downtown Vancouver. The study was funded in part with a grant from the Federation of Canadian Municipalities.

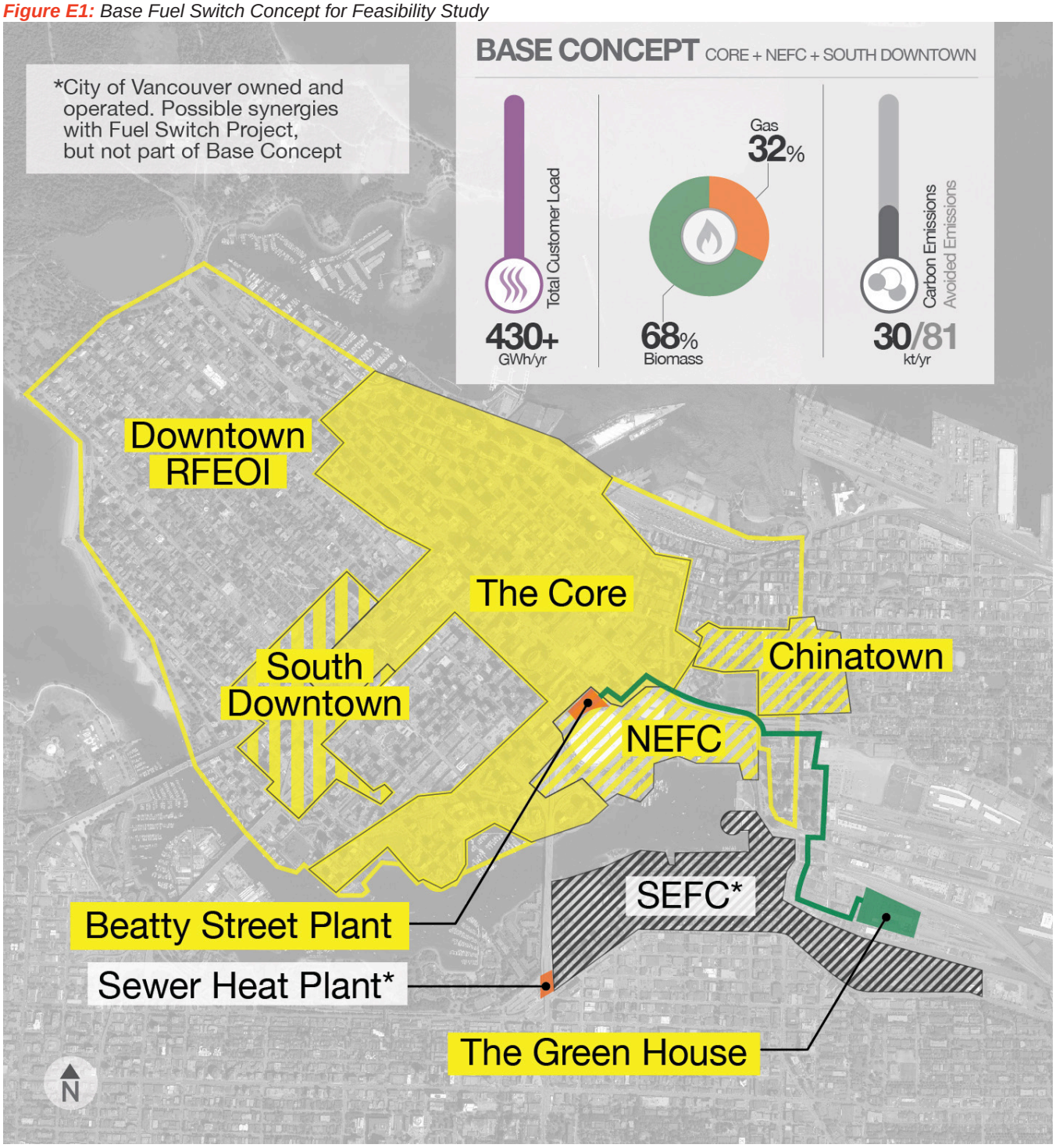
Key tasks in this study included:

- identification of a possible site for the project;
- an expression of interest from potential equipment vendors to establish representative technology costs and performance;
- an expression of interest from potential suppliers of clean urban wood waste;
- additional research on the long-term availability, cost and greenhouse gas (GHG) neutrality of clean urban wood waste;
- a preliminary site concept to inform analysis of building costs, aesthetic treatment of plant, fuel delivery opportunities, and other feasibility considerations;
- an air quality screening study;
- in-depth stakeholder interviews;
- detailed financial and policy analysis, including possible risks, uncertainties, optimizations, and enabling strategies; and
- assessment of project alternatives and comparators.

The bulk of the analysis in this study was completed by December 2015. Over the past year, Creative Energy has continued to monitor project drivers and input assumptions, and to meet with all levels of government and other stakeholders to discuss project scope, barriers and opportunities. These discussions are ongoing. Some key updates are incorporated in this final report.

The Creative Energy Fuel Switch would involve building a new low-carbon steam plant on City-owned land in the False Creek Flats. The target site is one of the only options for a project of this size and scope near downtown. The new plant would displace gas-fired steam from Creative Energy's existing steam plant (Figure E1). The project would also require a large new interconnection between the new steam plant and the existing steam plant. The Creative Energy network would still require the existing steam plant for peaking and back-up energy. The existing plant also acts as the distribution centre for the downtown network.

Figure E1: Base Fuel Switch Concept for Feasibility Study



A preliminary design for the new plant - referred to simply as the “Green House” - was developed by Bjarke Ingels Group and Henriquez Partners Architects (Figure E2). The preliminary concept includes an innovative rooftop farm and interpretive centre. The rooftop farm helps to reduce the project cost of energy, while also supporting a broader aesthetic and community vision for the site. At full build out, the rooftop farm could supply over 400 tonnes of local produce annually, enough to meet the needs of 10,000 people.

Figure E2: *Preliminary Design for the Fuel Switch Plant ("The Green House")*

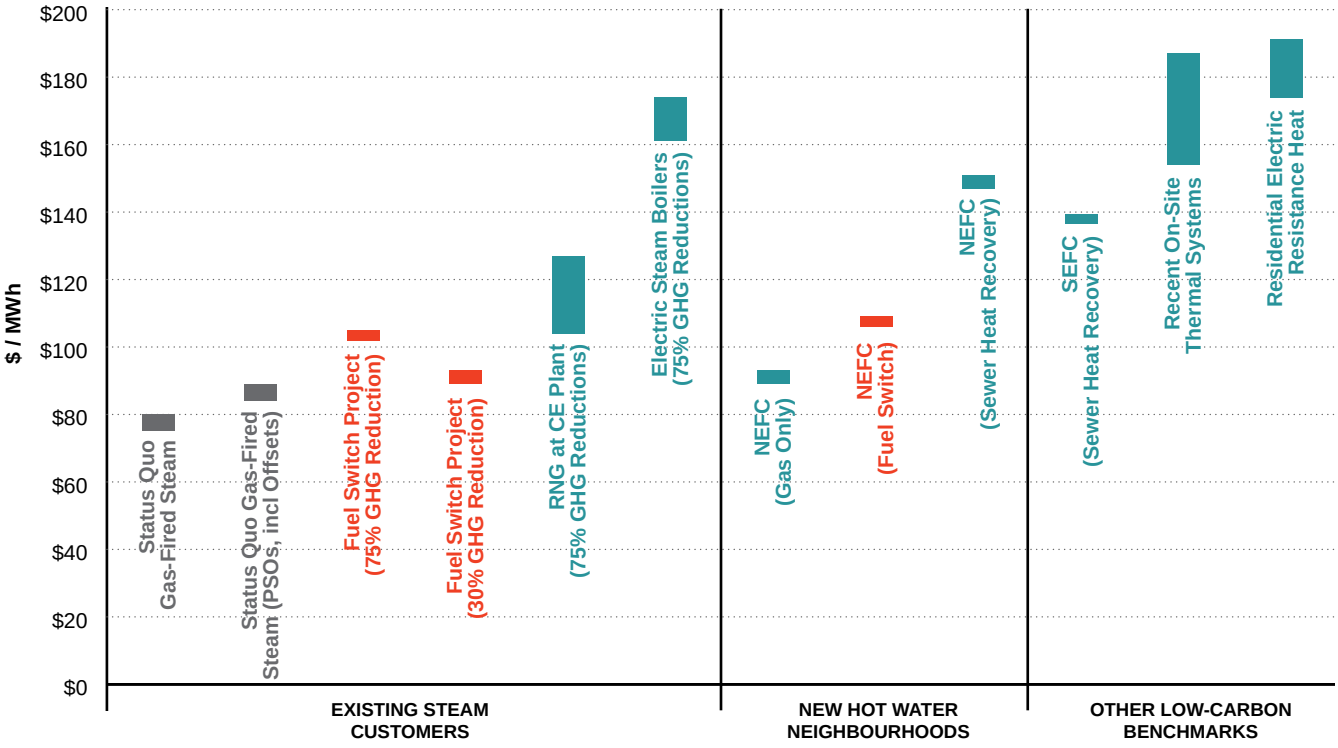
There are a limited number of technologies to produce low-carbon steam. The proposed solution uses clean urban wood waste, an approach with many local and global precedents. Local sources of clean urban wood waste include local park and forest management; demolition and land clearing activities; wood processing and manufacturing businesses; and the transportation sector. Until recently, about 50% of local urban wood waste still went to landfill. Starting in 2015, Metro Vancouver and member municipalities banned the disposal of clean wood waste to landfills. This project would be a catalyst for important upstream investments to enhance recovery of wood waste in the region.

The Fuel Switch is sized to supply baseload heat. In Vancouver, a low-carbon plant sized to 33% of peak demand can meet more than 75% of annual heating needs, with comparable reductions in greenhouse gas (GHG) emissions. This is the most cost-effective first step to reducing GHG emissions for heating. Further reductions are possible but will require costlier strategies and technologies to meet larger and more intermittent peak heating requirements. The initial target capacity for the Creative Energy Fuel Switch is about 65 MW. A plant of this size could reduce GHG emissions for all existing 200+ customers by 75%, while also meeting the carbon performance standards for all planned new development in Northeast False Creek (NEFC) and South Downtown. There is also room at the target site for a future expansion of the project.

The Fuel Switch could eliminate more than 81,000 tonnes of GHG emissions per year, which is equivalent to taking 16,500 cars off the road.

The Fuel Switch could eliminate more than 81,000 tonnes of GHG emissions per year, which is equivalent to taking 16,500 cars off the road. This is equal to 13% of the GHG offsets purchased by the Province in 2015 under its carbon neutral government commitment, which applies to government operations, school districts, health authorities, crown corporations, universities and colleges. The project represents approximately two thirds of the City's current GHG reduction targets from neighbourhood energy systems.

Figure E3: *Comparisons of Levelized Retail Rates**



** Projected levelized rates starting in 2020 for a period of 30 years under base case assumptions for Fuel Switch before further project optimizations or enabling tools.*

The Creative Energy Fuel Switch project supports GHG reduction targets established by the Government of Canada, the Province of B.C., and the City of Vancouver. It also contributes to other community objectives for local resource recovery, energy resilience, food production, green jobs, and education. The project could serve as a model and inspiration for achieving deep GHG reductions and other community benefits in dense urban neighbourhoods throughout Canada. There are about 160 known existing district energy systems in Canada, collectively serving approximately 2% of the national building stock. Today, many of these systems rely on natural gas. Expanding these systems, and switching them to low-carbon heat sources, represents an important opportunity for significant and cost-effective GHG reductions at a national scale. Further, the penetration of district energy in Canada is low relative to other jurisdictions that lead in renewable and low-carbon heat. There are many more opportunities for new thermal energy systems within dense urban areas of Canada to tap low-carbon heat sources that are not viable or cost-effective at smaller scales.

The Creative Energy Fuel Switch is technically feasible. It is also one of the largest and most cost-effective sources of renewable energy and carbon reductions in Vancouver, even before further project optimizations and enabling tools (Figure E3). The levelized cost of energy from the proposed Fuel Switch is cheaper than using renewable natural gas in Creative Energy's existing plant, or constructing a new electric steam plant. It is cheaper than a new sewer heat recovery plant to serve planned development in NEFC. It is even cheaper than the cost of expanding the City's existing sewer heat recovery plant that currently serves Southeast False Creek (SEFC). Even after including the additional cost of overheads, distribution, and peaking/back-up energy, the retail rates for both existing and new customers would be much lower than the cost of electric resistance heat, and lower than the cost of other recent on-site low-carbon energy projects registered with the BC Utilities Commission (BCUC).

▲ *Creative Energy's existing plant on Beatty Street, adjacent to BC Place.*

The low cost of the Fuel Switch is due in part to its economies of scale. But the project's size and lead time also pose implementation challenges under current market constraints, ongoing policy gaps, and recent regulatory decisions. There is also a minimum viable size for the project given high upfront costs for a new site, building and long interconnection.

A key challenge for this project is the disconnect between the long-term aspirations of all levels of government for deep GHG reductions, and the lack of existing policies to support those reductions. This is particularly important for time-sensitive investments such as the Creative Energy Fuel Switch. Land is scarce. Today's low interest rates help lower the cost of capital-intensive low-carbon projects, but these low interest rates are not expected to last indefinitely. There are some large new developments and existing buildings downtown facing near-term energy supply decisions, including a major new hospital campus. If potential customers are forced to pursue conventional systems or costlier low-carbon alternatives because of uncertainty or delays in the Fuel Switch project, this could reduce the ultimate number of customers available to support this more cost-effective investment. There may also be cost savings from coordinating the Fuel Switch project with other near-term infrastructure projects downtown such as the removal of the viaducts in NEFC.

The direct capital cost of the Fuel Switch project is about $135 million. For comparison, Creative Energy's current utility rate base (original capital cost less accumulated depreciation) is about $30 million. This is in part because low-carbon technologies are more capital intensive than conventional gas-fired generation. It also reflects the age of Creative Energy's existing assets (which remain in good condition), as well as the original cost of land for the existing steam plant, which was very low compared with today's land values. The replacement cost of the steam system would be over $100 million, even before accounting for the increase in the cost of land since the system was established in the 1960s.

The initial development and expansion of Creative Energy's steam system was secured with long-term customer contracts. However, most of Creative Energy's existing customers were connected many years ago, and many are now on month-to-month contracts. A significant new investment such as the Fuel Switch will require

▲ *Interior of Creative Energy's Existing Steam Plant*

new long-term contracts and/or other enabling strategies to offset the substantial investment risk in this project. While low-carbon electricity and renewable natural gas projects are able to access long-term fixed-price contracts to support their development, comparable support does not yet exist for large district energy-based renewable heating projects such as the Creative Energy Fuel Switch.

For new buildings in Vancouver which are subject to formal carbon performance standards, the cost of energy from the Fuel Switch is very competitive. However, the minimum viable size of the Fuel Switch project exceeds the requirements for new development in NEFC and South Downtown, neighbourhoods which were included in the anticipated demand for the Fuel Switch project. Fortunately, the feasibility study has also identified considerable additional development beyond NEFC and South Downtown that could benefit from the Fuel Switch project, including substantial new development in other proposed district energy zones outside downtown such as the Cambie and Broadway corridors. Unfortunately, current City policies and recent BCUC decisions also pose challenges for securing new development, in spite of the cost savings for end users. Current green building policies (and associated building certification standards such as LEED) require low-carbon solutions for individual developments to be in place at the time the new development is completed. But the lead time of the Fuel Switch exceeds the timeline for many near-term developments, potentially requiring these developers to implement smaller, costlier on-site solutions. This in turn reduces the demand available for a larger project. This sets up a perpetual chicken and egg problem for large but cost-effective projects such as the Fuel Switch.

To address the timing issues for near-term development while also providing the security to advance near-term investments in larger hot water networks and low-carbon supply projects, Creative Energy and the City of Vancouver developed a neighbourhood energy agreement for NEFC. This agreement was intended as a potential model for other neighbourhoods, and required BCUC approval. After an 18 month long process, BCUC accepted the technical solution for NEFC, but rejected the neighbourhood energy agreement between Creative Energy and the City for NEFC. The City is now exploring alternate policies and arrangements to overcome the barriers to developing larger and more cost-effective thermal networks and low-carbon supply projects in dense mixed use neighbourhoods where the timing and staging of individual developments is both uncertain and non-sequential.

The Fuel Switch was conceived in part to support Vancouver's 2011 Greenest City Action Plan (GCAP) and 2012 Neighbourhood Energy Strategy. A key action within both the GCAP and Neighbourhood Energy Strategy was to convert the existing legacy steam systems to low-carbon fuels. However, unlike new development, existing buildings in Vancouver have no formal carbon performance requirements. Although the Fuel Switch is a cost-effective source of low-carbon energy, it is still costlier than conventional gas-fired steam from Creative Energy's existing steam plant. Given a lack of long-term contracts and formal carbon policies for existing customers, the base case analysis assumes that existing customers would pay no premium for low-carbon energy. If Creative Energy were to charge a premium for low-carbon energy, many customers could install on-site gas-fired boilers, eliminating the GHG savings and stranding the investment in the Fuel Switch.

Under the assumption that existing customers would only pay the avoided cost of gas-fired steam, the present value of the financial gap between gas-fired steam and the Fuel Switch is over $160 million. This is a potential levelized premium of 40 – 45% over status quo bills for existing customers under current gas and carbon price forecasts (25 – 30% for Public Sector Organizations, which have slightly higher avoided costs due to their carbon offset requirements).

The base case analysis assumes an immediate 75% reduction in GHG emissions for existing customers. The cost premium for existing customers could be lowered by phasing in these reductions. But this would also require phasing the project and/or selling surplus energy or GHG reductions to other buildings or offset markets in the interim. Given economies of scale, phasing the project would also increase the near-term cost of energy and GHG abatement.

This financial gap is sensitive to future gas and carbon prices, which are volatile and uncertain. Natural gas price forecasts are near record lows, and there are no formal commitments to raise B.C.'s current carbon tax of $30 / tonne. The federal government has recently proposed a national floor on carbon prices of $50 / tonne by 2022. The federal government has also proposed a low-carbon standard for heating fuels, which could further raise the cost of conventional energy. While these proposals (which have yet to be confirmed) could significantly reduce the gap, they are not enough to eliminate it. They are also just interim steps, as they are well below the level required to achieve B.C.'s or Canada's GHG reduction targets for 2030, let alone 2050.

The cost of carbon abatement from the Fuel Switch project is lower than other project alternatives and comparators, and well below the estimated marginal abatement cost to meet B.C.'s and Canada's 2030 and 2050 targets.

Regardless of the outlook for gas and carbon prices, it would be unusual for a small utility such as Creative Energy to assume a large new investment risk with no long-term contracts and ongoing exposure to gas and carbon prices, particularly given that carbon prices and policies are within government control. Despite the financial gap under base case assumptions, the cost of carbon abatement from the Fuel Switch project is lower than other project alternatives and comparators, and well below the estimated marginal abatement cost to meet B.C.'s and Canada's 2030 and 2050 targets. The base case analysis is also conservative. This study has identified numerous project optimizations and alternate enabling strategies to secure investment in the Fuel Switch. However, many of these strategies will require partnerships with the City, the Province and the federal government.

One example of an opportunity for design optimization is the new interconnection. The cost of this interconnection could be reduced more than half by tunnelling under the railyards and using SkyTrain infrastructure for part of the alignment. There are precedents for both strategies. But these optimizations will require agreements with Translink and the owner of the railyards. The City can play a role in securing these agreements.

Property taxes represent a substantial portion of the Fuel Switch project costs under base case assumptions. The present value of property taxes under base case assumptions is nearly $49 million or one third of the base case gap. A substantial portion of these property taxes are incremental and would not exist without this project. The Fuel Switch project is a discretionary investment for existing customers. These customers already pay property taxes on the existing plant and this plant will continue to be required for peaking and back-up.

B.C. is also unique in Canada in having a separate classification for utility infrastructure. The mill rate for utility infrastructure in Vancouver is three times higher than the business rate, and even higher than major industrial rates. There is also considerable uncertainty in B.C. over the valuation of thermal distribution infrastructure. This is a relatively new area for the Assessment Authority. Rationalizing property taxes by excluding the interconnection (which would not exist in the absence of this project) and collecting taxes at the business rate (instead of the higher utility rate) would reduce the financial gap for the project by nearly $30 million and leave $11.5 million in property taxes, equivalent to expected taxes under other likely uses for the site. This rationalization in property taxes could be secured through changes in Creative Energy's Municipal Access Agreement, City ownership of the interconnection and/or a gross lease for the City-owned site of the Fuel Switch plant.

The proposed Fuel Switch plant is adjacent to the City's Neighbourhood Energy Utility in SEFC. The City will soon need to expand the existing sewer heat plant to provide low-carbon energy for growth of SEFC. The Fuel Switch project is a potentially cheaper source of additional low-carbon energy for SEFC. A supply contract with SEFC would help to reduce the financial gap and secure an initial investment in the Fuel Switch. The City could still advance the next increment of capacity at its existing sewer heat plant if or when additional low-carbon energy is required downtown.

In-depth interviews, market research and anecdotal evidence suggest some ability and willingness among existing customers to pay a premium for low-carbon energy. Large commercial customers, which make up about 30% of Creative Energy's existing sales, have indicated a desire for low-carbon energy to meet corporate commitments and/or attract green tenants. Some of these customers may see value in reducing their exposure to uncertain and volatile gas or carbon prices, since the cost of the Fuel Switch would be largely fixed. Small commercial customers and residential stratas are likely to be more price sensitive. Residential stratas will also be challenging given the collective purchase decisions required by strata councils and/or strata members. Creative Energy will need to confirm its existing customers' willingness to pay via new long-term contracts. Creative Energy intends to do this through a voluntary subscription process. Although Creative Energy expects voluntary subscriptions will make an important contribution to the financial gap, this process alone will not be sufficient to bridge the entire gap for existing customers. Creative Energy will require confirmation of other enabling strategies and project inputs (e.g., land lease) before expending time and resources on a subscription process. The success of the process could also be enhanced through greater clarity on likely future carbon policies for existing buildings.

Government buildings make up about 17% of Creative Energy's existing sales. There are also other existing gas-fired government buildings in downtown Vancouver that are not yet connected to Creative Energy, most notably Canada Place which is owned by the federal government and has a large gas-fired steam plant near the end of its expected life. Both the City and federal government have commitments to purchase renewable and low-carbon energy for their operations. Under B.C.'s carbon neutral

▲ *An urban rooftop farm in Montreal.*
▼ *A daytime rendering of the Fuel Switch Plant ("The Green House").*

government commitments, provincial Public Service Organizations (PSOs) in B.C. pay an additional cost of $25 / tonne to offset GHG emissions from gas-fired steam (equivalent to an additional $7 / MWh of steam purchased). The City, Province and federal government can directly support the project by committing to purchase low-carbon energy from the Fuel Switch. This represents a cost-effective strategy to achieve deep reductions in government buildings. Government leadership in purchasing low-carbon energy would not only help secure the initial investment but could also enhance the success of a voluntary subscription process for private buildings.

A conservative value of these five enabling strategies – interconnection optimizations, property tax rationalizations, sales to SEFC, government leadership in purchasing low-carbon energy, and voluntary subscriptions for existing buildings – would reduce the financial gap for existing buildings to less than $70 million (Figure E4). This also assumes no further changes in carbon prices or policies for existing buildings. None of the above strategies involve new financial commitments by the City or other levels of government. The rationalization of property taxes brings these taxes in line with what would occur in the absence of this project. The sales contract to SEFC would defer new City investment in sewer heat recovery and lower future SEFC rates. All levels of government already have commitments to purchase green energy and this project is a cost-effective option to meet those commitments. Finally, clarification of future policies for existing buildings does not require financial commitments by any level of government.

Additional strategies will still be required to bridge the remaining gap. Fortunately, there are several possible packages of strategies to do this (Figure E4). However, some of these additional strategies will require new financial commitments from the City and/or other levels of government.

The City can reduce the gap through financial enabling tools such as deferring remaining property taxes or land rent. These deferrals represent an opportunity cost for the City, but

Figure E4: *Enabling Strategies to Reduce the Financial Gap*

do not require new investments. The recovery of deferred costs could be tied to future gas and carbon prices or other revenues for the project (from offsets or connection of new development). The City could also own the interconnection and possibly the building that houses the Fuel Switch plant, and could finance these pieces of infrastructure with 100% debt (lower cost of capital than Creative Energy) and could also defer payment of these carrying costs similar to property taxes and land rent. City ownership of certain assets may also help in securing grants from senior levels of government. The deferral of remaining property taxes, land rent and financing costs for the interconnection (and possibly building) could reduce the gap under current gas and carbon prices by another $30 – 40 million. Only a fraction of these costs would be related to new investments or cash outlays by the City. Using Treasury Board of Canada guidance for discounting GHG benefits, the implicit cost of carbon abatement from an investment of $30 – 40 million by the City would be equivalent to $35 – 45 / tonne of GHG reduction. This represents a maximum financial exposure, and the dependence on the City's financial enabling tools could be reduced with increases in gas prices, carbon prices (including a proposed federal low-carbon standard for heating fuels), offset sales, or voluntary subscriptions (e.g., through introduction of carbon performance standards for existing buildings).

The City could also reduce the gap through policies that would secure more new development for the project. As noted previously, the Fuel Switch represents a cost-effective source of low-carbon energy for new development sites which have formal carbon performance requirements. The City could extend the reach of the Fuel Switch to buildings which aren't connected to Creative Energy's steam network by recognizing carbon credits. The Fuel Switch would displace gas-fired energy for existing buildings with no carbon performance requirements; these environmental benefits could be credited towards non-connected buildings which have carbon performance requirements. These buildings would contribute to the cost of the Fuel Switch, helping secure this time-sensitive investment in low-carbon energy. Other low carbon projects could be advanced if or when new development patterns or government policy mean additional carbon reductions are needed. This could include a second phase of the Fuel Switch, the expansion of the sewer heat plant in SEFC, or new low-carbon projects in other neighbourhood energy systems.

The above paths require considerable financial commitments on the part of the City and/or a lowering of near-term targets for existing buildings. Another strategy to lower the gap while supporting reductions in existing buildings is a grant from senior levels of government. There are currently no provincial grant programs for a project such as the Fuel Switch.[i] In its 2016 budget, the federal government announced new investments of $11.9 billion in public transit, green infrastructure and social infrastructure. The federal government's *Fall Economic Statement* proposed an additional $81 billion through to 2028 in public transit, green and social infrastructure, transportation infrastructure that supports trade, and rural and northern communities. The federal government also announced it will establish a new Canada Infrastructure Bank, an arm's-length organization intended to increase investment in growth-oriented infrastructure. The federal government has also announced a $2 billion Low Carbon Economy Fund, which is expected to begin in 2017. This fund is intended to support concrete measures that generate new, incremental GHG reductions while considering cost-effectiveness. In total, the federal government has committed more than $180 billion in infrastructure funding to 2028.

The Fuel Switch project aligns very well with the policy objectives for federal infrastructure funding and the Low Carbon Economy Fund. The Low Carbon Economy Fund is the most promising source of funding in terms of alignment and timing. However, the design of federal programs to access new infrastructure and low-carbon funds have yet to be announced.

i For comparison, the Province has recently announced a $40 million Clean Energy Vehicle Program which will provide incentives of $5,000 to $6,000 for consumer purchases of electric vehicles. The program will fund up to 6,500 electric vehicles. The implicit carbon abatement cost of this program is $85 - $100 / tonne. The Fuel Switch would reduce GHG emissions equivalent to removing 16,500 cars, with an implicit carbon abatement cost of ~$85 / tonne after property tax rationalization and design optimizations.

As a regulated utility, any grants received by Creative Energy directly would reduce Creative Energy's net investment and rate base. Grants go directly to reducing customer rates (or, in the case of existing customers, the gap between status quo costs and the cost of service for the Fuel Switch). The net effect of a grant would be the same if the grant was provided to the City to pay for specific assets owned by the City. A federal grant of $50 million could eliminate the residual financial gap after other enabling tools, while ensuring maximum reductions for existing buildings and reducing additional financial commitments from the City. This is equivalent to $40 / tonne of emission reduction. Like deferred City costs, a federal grant is only required to bridge the gap between project costs and current carbon prices and policies. The federal grant could also be made recoverable based on future gas and carbon prices or other revenues arising from future changes in carbon policies.

In the absence of formal grant programs, the Province could still support the project through the purchase of offsets. In 2015, the Province purchased nearly 625,000 tonnes of GHG offsets to meet its carbon neutral commitments. The bulk of these offsets were from the forestry sector, including investments in forest sequestration, and fuel switching in the pulp and paper sector from natural gas to wood residues. In 2015, the government purchased offsets for $9 - $15 / tonne and charged PSOs $25 / tonne to cover administrative costs for the program. The Province expects to require over 650,000 tonnes per year of new offsets by 2021 (as current offsets expire). In July 2016, the Climate Investment Branch issued a new Request for Offset Units (RFOU). Under the RFOU, applications will be accepted on a rolling on-going basis until July 19, 2021. The Province has also indicated a desire to diversify its portfolio, including securing offset projects within the building sector. The Fuel Switch project is one of the largest and most cost-effective GHG reduction projects in the building sector. It is also a price-regulated, open books project. However, the Province's current target price is not sufficient to secure significant offsets in the building sector or to eliminate the gap for the Fuel Switch project.

Creative Energy has proposed an innovative dynamic pricing option which would establish a higher initial price for offsets from the Fuel Switch, but then lower this price with future increases in gas and carbon prices. Offset sales are limited to a 10 year term and could be used to phase-in reductions for existing customers. Creative Energy has submitted a preliminary Project Information Document (PID) to the Climate Investment Branch, which is the first step in securing an offset sale to the Province. Creative Energy cannot finalize the sale of offsets to the Province until

the City confirms that other enabling tools are available, as well as the acceptability of offset sales to address the residual cost gap.

There are other strategies that could reduce the cost gap or reduce the project's reliance on financial enabling tools. Some of these would add to project complexity (e.g., combined heat and power) or reduce project benefits and increase carbon abatement costs (e.g., reducing the size of the project). Other optimizations will not be confirmed until the detailed design, construction and/or operating phases of the project. Creative Energy will continue to consider and pursue these opportunities, but cannot rely on these to support an initial investment decision.

Given the current stage of discussions with the City and other levels of government it is unlikely the Fuel Switch project can be complete by the City's original target date of 2020. The final project schedule is uncertain because it will depend on the timing of near-term decisions by the City and other levels of government with respect to the various enabling strategies above. It will also depend on the timeline for key regulatory approvals, including the time required to secure a Certificate of Public Convenience and Necessity (CPCN) from the BCUC.

The key next step to advance the Creative Energy Fuel Switch is a Project Enabling Agreement with the City of Vancouver. This agreement should confirm:

- mutual understanding of project goals, scope and structure;
- land lease (including option on neighbouring site to allow future expansion);
- commitments to purchase Fuel Switch energy or carbon credits for City buildings;
- commitments of City-controlled urban wood waste;
- a purchase agreement with the City's SEFC NEU;
- any policy commitments and financial enabling tools to be provided by the City to advance the project, including cost recovery mechanisms; and
- the respective roles and responsibilities of the City and Creative Energy in advancing the project.

The feasibility study serves to illustrate the gap between long-term climate targets and current policies at all levels of government.

The Project Enabling Agreement will provide the necessary clarity and security to proceed with other key development tasks including securing federal grants, negotiating the sale of offsets with the Province (if allowed under the Project Enabling Agreement), commencing negotiations for fuel supply contracts, initiating the voluntary subscription process, and conducting customer and community consultations. These activities will need to be complete prior to the CPCN submission, which will be required prior to detailed design, tendering and construction.

The feasibility study has confirmed the technical viability, cost-effectiveness, and environmental benefits of the Creative Energy Fuel Switch project. But it also serves to illustrate the gap between long-term climate targets and current policies at all levels of government. The feasibility study has identified multiple strategies to address this gap in order to secure this important but time-sensitive low-carbon legacy for Vancouver. This project and associated enabling strategies could also serve as a model and inspiration for the low-carbon transition in other existing thermal networks and dense urban areas throughout Canada. The path forward will require support and collaboration from all levels of government.

CREATIVE ENERGY FUEL SWITCH: QUICK FACTS

PROJECT DESCRIPTION:

- New low-carbon energy plant to produce 75% of Creative Energy's steam
- Creative Energy's existing steam plant retained for peaking and back-up
- New interconnection line connecting new plant to existing plant and distribution system

TARGET PROJECT SIZE:

65 MWt

- Potential for a future expansion, which could include other technologies or uses

TARGET FUEL / TECHNOLOGY:

- Clean urban wood waste (recently banned from landfill; sufficient long-term supply; carbon neutral under all provincial, national and international carbon accounting protocols).
- Final production technology to be selected in a competitive tender process. Preliminary short-list established.
- Meets or exceeds all local air quality standards.

DIRECT CAPITAL COSTS:

PROJECT COMPONENTS	2020 $ (MILLIONS)
New Interconnection	$24
Building	$35
Plant	$75
Total	**$135**

GHG REDUCTIONS:

- **81,000 tonnes / year ***
- Equivalent to **16,500 cars** or 13% of Province's offset purchases in 2015

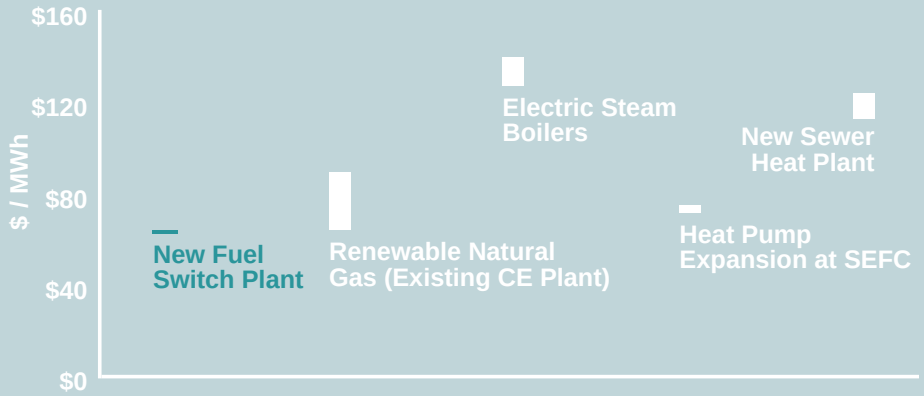
** excludes any avoided upstream emissions from gas production, processing and transportation.*

OTHER PROJECT ELEMENTS / BENEFITS:

- Rooftop farm
- Interpretative centre
- 50+ direct and indirect green jobs
- Option to add electricity generation (combined heat and power)
- Upstream investments in advanced waste recovery

COST-EFFECTIVENESS:

- Least-cost source of large-scale GHG reductions for existing and new buildings



KEY CHALLENGES:

- Large and time-sensitive project
- Low natural gas and carbon price outlook
- Lack of formal carbon policies for existing buildings
- Lack of long-term contracts with existing customers
- Lack of security for new customers (uncertainty over city connection policies; recent BCUC decision on neighbourhood energy agreements)
- Lack of current federal or provincial incentives for low-carbon district heat projects
- High property tax rates for utilities

KEY OPPORTUNITIES:

- Further capital and operating cost savings
- Property tax rationalization
- Recoverable federal grants (infrastructure or low-carbon economy funds)
- City financial enabling tools (land and infrastructure leases tied to future gas and carbon prices)
- Interim allocation of energy or GHG reductions to new development with formal carbon performance requirements
- Sale of offsets to Province
- Voluntary subscription process for existing customers (supported by clear carbon policies for existing buildings comparable to new development)

CONTENTS

LIST OF ACRONYMS

AAQOs	Ambient Air Quality Objectives
BC Hydro SOP	BC Hydro Standing Offer Program
BCUC	British Columbia Utilities Commission
BDT	Bone Dry Tonne(s)
CHP	Combined Heat and Power
CEMS	Continuous Emissions Monitoring System
CO	Carbon Monoxide
CPCN	Certificate of Public Convenience and Necessity
GCAP	Greenest City Action Plan
GHG	Greenhouse Gas(es)
GST	Federal Goods and Services Tax
IDC	Interest During Construction
LTRP	Long Term Resource Plan
MWe	Megawatt of Electricity Output
MWt	Megawatt of Thermal Output
NEA	Neighbourhood Energy Agreement
NEFC	Northeast False Creek
NO_x	Nitrogen Oxides
PM	Particulate Matter
PSO	Public Service Organization
PST	Provincial Sales Tax
RFEOI	Request(s) for Expressions of Interest
RFI	Request(s) for Information
RNG	Renewable Natural Gas
SEFC	Southeast False Creek
UCA	Utilities Commission Act
VOCs	Volatile Organic Compounds
WACC	Weighted Average Cost of Capital

1. PROJECT CONTEXT

1.1 ORIGINS OF THE OPPORTUNITY

In the 1960s, many buildings in downtown Vancouver were still heated by dirty fuel oil and in a few cases even by coal. Some buildings used centralized gas-fired boilers for heating, but both the technology and its application at the time was not as efficient as we have come to expect today. In response to these challenges, in 1968 a group of local energy innovators and entrepreneurs established a community energy system they called Central Heat Distribution Ltd. to provide cleaner and more efficient heating to buildings and businesses in downtown from a centralized steam plant located in the former Vancouver Sun Press Building at 720 Beatty Street.

From a global perspective, district heating was by no means new. Centralized heating dates from the Roman Empire and earlier. And many large cities in Europe and North America already had long-established district heating systems. But this was very novel at the time for a relatively young city like Vancouver, and it made an important contribution to downtown Vancouver by improving local air quality. The system would also have reduced greenhouse gas (GHG) emissions (switching buildings from oil or less efficient on-site heating options of the day to centralized natural gas heating) long before GHG was a concern.

By 2014, Central Heat had grown to one of the largest district energy systems in Canada, with about 14 km of steam pipes providing reliable heating (99%+ reliability over 45+ years) to over 210 buildings, including landmarks such as St. Paul's Hospital, BC Place, the Vancouver Public Library, and the Queen Elizabeth Theatre, along with many other office and condo towers. Both St. Paul's Hospital and BC Place are deemed critical facilities in the event of a major disaster such as an earthquake. The distribution system and central steam plant are still in excellent condition today.

▲ *Top: 720 Beatty Street plant in 1960s; Bottom: Original steam network.*

The foresight and hard work of these early energy innovators and entrepreneurs has created a unique opportunity to support new community priorities such as the transition to a low-carbon and renewable energy future. This centralized system now represents one of the single largest

opportunities to reduce GHG emissions and increase local and renewable energy supply in Vancouver. The system opens up opportunities to tap low-carbon and renewable energy sources not available, appropriate or cost-effective at the scale of individual buildings. And the size of the system provides significant economies of scale, flexibility and risk diversification.

1.2 ACQUISITION OF CENTRAL HEAT & AGREEMENTS WITH THE CITY

Creative Energy Canada Platforms Corp. acquired Central Heat in early 2013 with a vision to expand and decarbonize district energy in downtown Vancouver. In November 2013, the British Columbia Utilities Commission (BCUC) approved the acquisition. In March 2014, Central Heat was rebranded as Creative Energy Vancouver Platforms Inc.

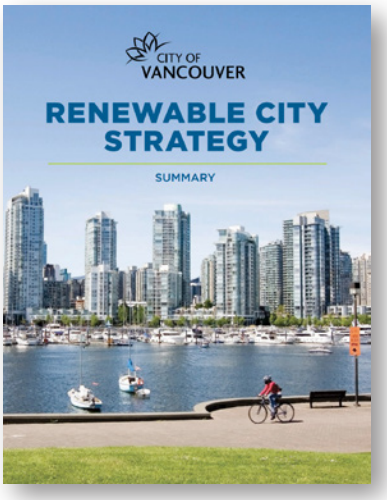
Following a competitive Request for Expressions of Interest (RFEOI) for Neighbourhood Energy Concepts for Downtown Vancouver, the City of Vancouver (the City) selected Creative Energy Canada as the preferred proponent. In November 2013, the City and Creative Energy signed a Memorandum of Understanding (MOU) to guide further study and negotiations for a low-carbon fuel switch of the existing steam system and opportunities to expand low-carbon district energy downtown, starting with the negotiation of a Neighbourhood Energy Agreement (NEA) to develop a new hot water network and low-carbon energy supply serving Northeast False Creek (NEFC) and Chinatown. In January 2014, Creative Energy was awarded a grant from the Green Municipal Fund administered by the Federation of Canadian Municipalities (FCM) to support a detailed feasibility study of the Fuel Switch project.

In May 2014, Creative Energy and the City executed a NEA for NEFC and Chinatown. An application was subsequently filed with the BCUC in April 2015 seeking a Certificate of Public Convenience and Necessity (CPCN) and approval of the NEA. In December 2015, the BCUC granted a CPCN for the NEFC and Chinatown hot water network but rejected the NEA. The Commission subsequently rejected an Amended NEA filed in response to its initial decision and also a request for reconsideration of its decision regarding the amended NEA. As of the writing of this report, Creative Energy and the City do not have any formal agreement for NEFC and also no prospect for one under the conditions established by the BCUC (discussed further below).

On December 7, 2016, the City gave notice that it was closing the RFEOI for Neighbourhood Energy Concepts for Downtown Vancouver and was terminating the MOU with Creative Energy. The City remains committed to its Neighbourhood Energy Strategy but, in light of the Commission decision and other market / policy constraints, the City is now exploring options to support the Fuel Switch and expansion of neighbourhood energy which are outside the scope of the original RFEOI.

1.3 CITY OF VANCOUVER POLICIES AND PLANS

The City began taking direct action to reduce GHG emissions with the Clouds of Change Report in 1990. In 2008 City Council passed a motion to reduce GHG emissions by 80% over 2007 levels by 2050, and in the same year Vancouver signed the Climate Action Charter. That Charter, signed by 180 of BC's 188 local governments, committed the City to reducing GHG emissions. The Province's 2008 Green Communities legislation also required cities such as Vancouver to develop a formal GHG emissions reduction plan.



In July, 2011, Council adopted the Greenest City 2020 Action Plan (GCAP) and directed staff to begin implementing the highest priority actions. The GCAP set a target of 33% reduction in GHG emissions by 2020 from 2007 levels, and also set the long-term goal to eliminate dependence on

fossil fuels. One of the key actions in the GCAP to achieve this 33% reduction target is the large-scale deployment of sustainable thermal energy systems for high-density, mixed-use neighbourhoods.

In October 2012, Council approved the Vancouver Neighbourhood Energy Strategy and Energy Centre Guidelines, to help achieve the GCAP objectives. The City's Neighbourhood Energy Strategy includes two key actions: 1) convert the existing legacy steam heat systems in the City (e.g., Central Heat, Vancouver General Hospital and Children & Women's Hospital) to low-carbon fuels; and 2) establish new low-carbon neighbourhood energy systems in high density growth areas of Vancouver.

Following directions in the GCAP and Neighbourhood Energy Strategy, in December 2012 the City issued a RFEOI for Neighbourhood Energy Concepts for Downtown Vancouver. In July 2013, the City also issued a Request for Proposals for Neighbourhood Energy Supply to the Cambie Corridor. The City selected Creative Energy as the preferred proponent in Downtown and also in South Cambie.

In November 2015, the City issued its Renewable City Strategy which established a target that 100% of the city's energy would come from renewable sources by 2050. Strategies to achieve this target include the conversion of Creative Energy's steam network from natural gas to renewables and further expansion of low-carbon district energy.[1]

In parallel with the above policies the City has established a number of Green Building policies. Currently new developments applying for rezoning must achieve LEED Gold with additional energy reductions. In July 2016, Council approved a Zero Emissions Building Plan that established both GHG and thermal energy limits by building type.[2] These requirements apply to the initial design of buildings and the City intends to ratchet limits down over time. By 2025 most new buildings will have to be designed to achieve emission reductions of 90% compared to 2007 standards. By 2030, all new buildings will have to be designed to achieve zero emissions. These requirements can be met through a combination of envelope improvements and connection to low-carbon neighbourhood energy systems. The City has yet to release further implementation details to support the Plan. These include required amendments to the City's bylaws, policies, and guidelines together with clearer guidance on the interaction between the Zero Emission Building Plan and the Neighbourhood Energy Strategy (including proposed boundaries for low-carbon district energy systems).

The City's Green Building policy currently applies only to the initial design of new buildings. To date the City has not developed any policies to promote renewable or low-carbon energy in existing buildings or any specific policies to support a fuel switch for existing steam customers.

1.4 PREVIOUS SCREENING STUDIES FOR THE FUEL SWITCH

Prior to the acquisition of Central Heat by Creative Energy, there were two screening studies conducted on a low-carbon fuel switch for Central Heat.

The first screening study was completed in 2010 as part of a district energy screening study for the NEFC neighbourhood, which was commissioned by the City, Central Heat and NEFC landowners under Vancouver's Eco-Density policy for large development sites. This study compared the costs and benefits of a new low-carbon baseload steam plant serving both existing steam customers and new hot water customers in NEFC versus a new (smaller) low-carbon baseload hot water plant serving NEFC only. There are fewer options to produce low-carbon steam but there are potential economies of scale with a larger plant. Options considered to supply low-carbon hot water included biomass, gas-fired combined heat and power (CHP), sewer heat recovery (similar to the City's exist Neighbourhood Energy Utility (NEU) in Southeast False Creek (SEFC)), and waste heat recovery from commercial cooling systems (e.g.,

1 The full document is available at: http://vancouver.ca/files/cov/renewable-city-strategy-2015.pdf.
2 The staff report can be found at: http://council.vancouver.ca/20160712/documents/rr2.pdf.

Roger's Arena) and a local BC Hydro substation. Options considered to supply low-carbon steam included biomass (thermal only or CHP configurations) and a gas-fired CHP. All biomass options were designed to use clean urban wood waste. The 2010 study also examined general siting options for a larger plant.

In the 2010 study, biomass screened better than other low-carbon alternatives. A larger plant was also found to have significant economies of scale (lower costs) compared with a smaller plant. However, the study also found that a larger biomass plant would still be more costly than conventional gas-fired steam from Creative Energy's existing plant. This posed a challenge because there were no low-carbon mandates for existing customers (a situation that has not changed). The study identified siting and fuel availability for a larger biomass plant as key risks and uncertainties that would require more due diligence.

A second screening study was completed for the City and Port Metro Vancouver (the Port) in early 2013. The 2013 study focused solely on the larger plant options. This second study updated assumptions for capital and fuel costs. It also considered some alternate scenarios for customers and plant locations. Specifically, the 2013 study explored the possibility of serving both the facilities within the Port lands and existing downtown customers. The Port lands include two large industrial operations – Rogers Sugar and West Coast Reduction – each with significant process steam needs. The new concept considered an even larger plant (90 MW vs. 65 MW) and possible additional locations within the Port lands. The study also considered whether a location within the Port lands could provide additional value for CHP given ongoing electrification of the Port and local electric system constraints.

A plant located at the Ports would require a longer interconnection to downtown, but the hope was that higher interconnection costs would be offset by the increased size of the plant (economies of scale), possibilities for barge delivery of fuel (lower cost than truck or rail), possible lower cost of land (and lower property taxes), improved plant utilization as a result of more year-round steam demands for potential industrial customers, and possible synergies with ongoing Port electrification (through addition of CHP). The study showed theoretical promise from locating a plant within the Ports, but noted additional challenges. These included short-term variability and long-term uncertainty in industrial operations within the Ports; limited incentives for industrial loads to purchase low-carbon energy; a limited number of viable locations for an energy plant in the Port lands; the Port concerns about the compatibility of an energy plant with the Port's primary mandate for trade; uncertainty over the magnitude of local electric system constraints (information was not forthcoming from BC Hydro); and lack of existing mechanisms to monetize any local electric system benefits within the project.[3]

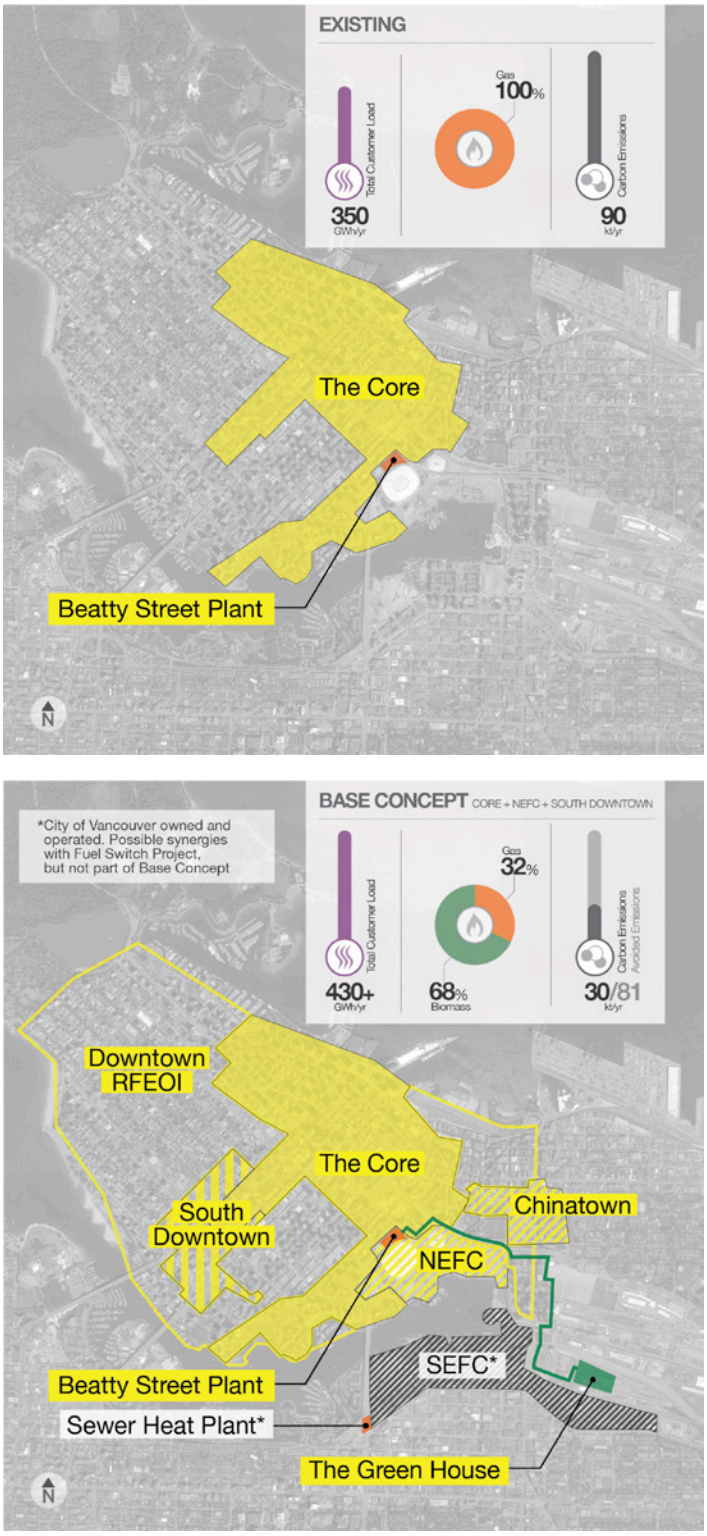
The detailed feasibility study summarized in this report builds on the concepts and data for the Fuel Switch that were developed in these earlier screening studies. The base concept in this detailed feasibility study focuses on the use of clean urban wood waste (both with or without CHP). However, there is additional analysis of other project alternatives. This feasibility study also considers sites for a new plant within the Port lands. However, based on the findings of the 2013 screening study, there was no further consideration of supplying existing industrial loads within the Port lands.

1.5 GENERAL CONCEPT FOR THE FUEL SWITCH

The concept considered in this feasibility study is referred to simply as the Fuel Switch. The project does not actually involve switching the fuel for Creative Energy's existing gas-fired steam plant at 720 Beatty Street. Rather, it would involve constructing an entirely new low-carbon steam plant at another location to displace gas-fired steam from Creative Energy's existing plant (Figure 1). Given the high capital costs for a

3 Unlike large institutions such as SFU and UBC, the electric grid within the Port lands is owned and operated by BC Hydro rather than Port Metro Vancouver. This limits the opportunities for an embedded CHP plant that is not behind a customer meter.

Figure 1: *Existing System vs. Proposed Expansions and Fuel Switch*



new low-carbon plant (including the need for a lengthy new interconnection), the new plant is sized to meet baseload heating demands. A baseload plant sized to about one third of system peak would maximize the utilization of all new infrastructure and could supply up to 75% of annual heating needs. The new plant would be interconnected to the existing steam network via the existing plant, which would continue to be used for peaking and back-up.

Creative Energy and the City have also been considering opportunities to expand the reach of district energy downtown, including the development of new hot water networks connected to the existing steam system. Hot water distribution opens the possibility for a wider range of low-carbon technologies (including waste heat recovery). Over time it is expected that the entire steam network will eventually be converted to hot water. However, immediate conversion of the existing steam network to hot water would be very costly given its current age and condition and also the very high costs of replacing existing infrastructure in a congested urban setting. In the near-term, Creative Energy plans to use hot water distribution for major new extensions (neighbourhoods) where possible. These new hot water networks can be interconnected with the steam system via centralized steam-to-hot water converter stations, which opens up the possibility to share energy sources, supporting greater economies of scale and integration.

When this feasibility study was initiated, discussions for new franchise areas were most advanced for NEFC (including Chinatown) and the area known as South Downtown.[4] These two neighbourhoods were considered in target sizing of the Fuel Switch. At build out, these neighbourhoods would have together accounted for at least

4 South Downtown is defined approximately as the area between Thurlow St. to the west, Richards St. to the east, Nelson to the north, and False Creek to the south. Creative Energy's network does not extend into South Downtown. There has recently been a significant amount of development in South Downtown, which now represents a lost opportunity for low-carbon district energy (since many of these buildings either rely on electricity and/or brand new gas-fired boiler plants). Development in South Downtown is more spread out than in NEFC, but there are several large development nodes. But there is still significant development planned, particularly around the Granville loops and along Burrard Street. Compared to NEFC, the area is also further from the existing steam network.

17% of the output under base case assumptions in this feasibility study.[5] These and other new neighbourhoods support the feasibility of the Fuel Switch in three ways. First, more customers help lower the unit cost, which exhibits significant economies of scale in terms of production equipment; fixed labour requirements; and high initial fixed costs for a new site, new building, and lengthy new interconnection. Second, unlike existing buildings most new construction has formal carbon performance requirements. Because the Fuel Switch is very cost-effective compared to other options for meeting these carbon performance requirements, there is an opportunity to recover the full cost of energy from any portion of the Fuel Switch allocated to new development areas. This not only results in lower rates for new development areas (compared to other alternatives) but helps to reduce any outstanding financial gap associated with providing low-carbon energy to existing customers (before other contracting or enabling strategies discussed further in this report). Finally, the proposed franchise agreements between Creative Energy and the City for new neighbourhoods would have established formal carbon performance requirements for these neighbourhoods as a whole and would also have permitted Creative Energy to defer those requirements to allow time either to develop the larger Fuel Switch or to permit more optimal scaling and timing of other low-carbon alternatives. Under the proposed franchise agreements, the City would also have provided connection policies to secure investments in both networks or low-carbon energy sources (such as the Fuel Switch) required in advance of individual developments given uncertainty over the timing and sequencing of development.

Since completion of the bulk of the analysis for this feasibility study, the Commission has rejected the proposed franchise agreement for NEFC and Chinatown, which the City and Creative Energy had also hoped to replicate in South Downtown and potentially other new neighbourhoods downtown and in South Cambie. The Commission decision has increased investment risks for both new networks and the larger Fuel Switch. The Commission decision and its implications for the feasibility of the Fuel Switch are discussed further below.

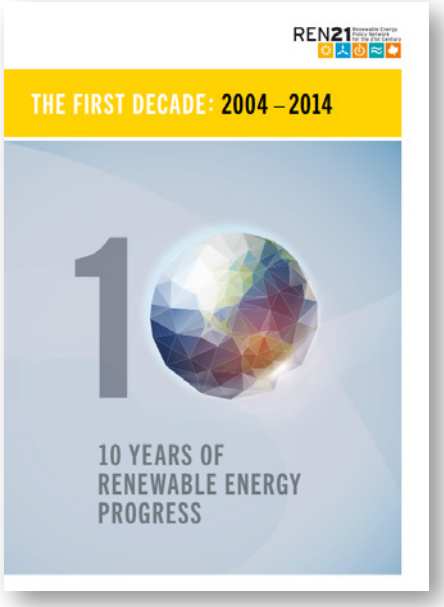
1.6 GLOBAL CONTEXT

Considerable progress has been made globally in advancing renewable and low-carbon electricity. However, progress towards renewable heating and cooling, which account for almost half of total global energy demand, has been much slower. The Renewable Energy Policy Network for the 21st Century (REN21) calls renewable heating and cooling the “Sleeping Giants” of renewable energy policy. REN21 argues: “To achieve the transition towards renewable energy, more attention needs to be paid to the heating and cooling and transport sectors, as well as to integrated approaches that facilitate the use of renewables in these sectors.” [6] Despite the aggressive commitments to renewable energy emerging among nations and cities, REN21 notes that the heating and cooling sectors “…lag far behind the renewable power sector when it comes to policies that support technology development and deployment.”

This is illustrated starkly in Germany’s so-called *Energiewende* –the planned transition to a renewable economy. Germany has made significant progress towards renewable electricity in recent years with some very aggressive and costly policies. According to REN21, renewables provided 25.4% of Germany’s total electricity consumption in 2013 (up from only 11.6% in 2006). In contrast, renewables still account for only 10.2% of heating demand (up from 6.2% in 2006) and 5.9% of transport fuels (excluding air traffic). In 2013 renewables accounted for only 12.3% of Germany’s total energy consumption in all sectors combined. A recent study from the German renewable energy association (BEE)

5 Base case demand forecasts for these neighbourhoods do not include be potential new development capacity in NEFC from removal of the viaducts; new development in Chinatown (which is less certain); or potential redevelopment of the current site of St. Paul’s Hospital.

6 REN21 is an international non-profit association and is based at the United Nations Environment Programme (UNEP) in Paris, France. The quotes here are from The First Decade: 2004 – 2014. 10 Years of Renewable Energy Progress which can be found at: http://www.ren21.net/Portals/0/documents/activities/Topical%20Reports/REN21_10yr.pdf. A 2016 update found that awareness of renewable heating and cooling is increasing but policy support remains far below support in other sectors (http://www.ren21.net/wp-content/uploads/2016/06/GSR_2016_Full_Report.pdf).



finds that while Germany is set to achieve its targets for the electricity sector, it is unlikely to meet its carbon reduction target by the end of this decade or its long-term target for the share of renewables in all sectors. At its current rate of progress, Germany is set to meet its 2050 renewable energy target for the economy as a whole by 2097.[7]

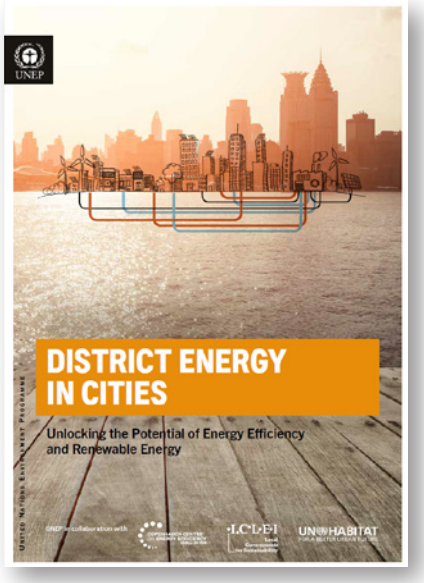
The electricity sector is characterized by large integrated grids with relatively few suppliers / production plants. Rapid growth in renewable electricity has been accomplished through powerful sector-wide policies such as forced retirement of coal and nuclear plants; renewable portfolio standards; feed-in tariffs and standing offers for renewable generators; strong tax incentives; and net metering programs. The heating and cooling sector is much more localized and fragmented, characterized by multiple decision makers and smaller scales. Information to support policy development is less available and more fragmented. Policy intervention has been equally fragmented, tending to focus mostly on individual building design (new construction) and electrification. Market barriers or failures for renewable heating and cooling are prevalent. These include split incentives, information asymmetries, practical constraints on consumers' ability to weight energy costs or influence initial technology selection, and collective decision problems (multi-owner or multi-tenant buildings). There are fewer policy levers targeting ongoing system performance (consumer behavior, maintenance of systems, replacement of technologies). Change is slow, reflecting the small scale and long-lived nature of heating and cooling systems.

Recognizing the importance of heating and cooling for climate protection, in February 2016 the European Commission released its very first comprehensive Heating and Cooling Strategy for the European Union (EU).[8] This strategy draws on the best practices of leading member states in removing barriers to decarbonizing buildings, communities and industry. It stresses both increased energy efficiency as well as increased use of renewables in the sector. It also stresses the need for integrated strategies to achieve greater linkages among sectors (e.g., CHP, thermal storage, waste recovery). Thermal networks in dense urban areas are identified as an important tool for increasing renewables and integration among sectors. These networks provide economies of scale and access to renewables not suitable or cost-effective at smaller scales, including large sources of waste heat from industry, electricity generation, sewage, and solid waste management. They also provide opportunities for significant thermal storage to minimize peak demands on electricity girds and help balance intermittent renewable electricity sources.

7 The report, in German, can be found here: http://www.bee-ev.de/fileadmin/Publikationen/20150419-Szenarien_SZEN-15.pdf. An English discussion of the report is available here: http://energytransition.de/2015/06/germany-to-miss-its-renewable-energy-target-for-2020/

8 See overview of strategy here: https://ec.europa.eu/energy/en/news/commission-launches-plans-curb-energy-use-heating-and-cooling. A recent overview of support activities and projects of the EU for energy efficiency and renewable energy in the heating and cooling sector (including expansion of district energy and fuel switching initiatives) can be found here: https://ec.europa.eu/energy/sites/ener/files/documents/overview_of_eu_support_activities_to_h-c_-_final.pdf.

Thermal networks are well established in many Nordic countries. For example, thermal networks supply 98% of Copenhagen's heating needs. More than 50% of building stock in Sweden is connected to thermal networks. Norway, which already has virtually 100% renewable electricity, is rapidly expanding district energy (further details below). Germany, Austria, France, the UK, the Netherlands and Belgium have lower penetration of thermal networks but are implementing many new policies and programs to increase penetration in support of their climate protection, resiliency and energy security goals.



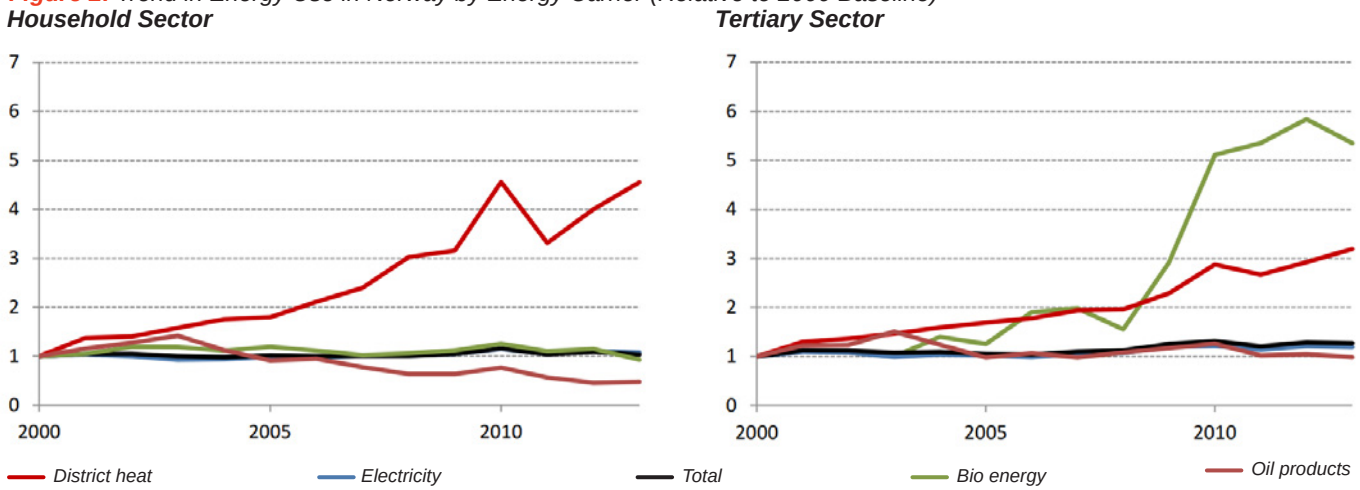
The EU Heating and Cooling Strategy highlights the important role for local governments in advancing renewable heating and cooling, including thermal networks. Until recently most national climate plans in the EU did not take into account local/regional actions and vice-versa. Numerous initiatives are now under way to bridge the gap between EU policies, national objectives and effective decision making at regional and local levels. Article 14 of the EU's Energy Efficiency Directive calls on member states to carry out a comprehensive assessment of their potential for efficiency in heating and cooling. Article 22 (3) of the EU's Directive on Energy from Renewable Sources requires the member states to indicate geographical locations suitable for exploitation of energy from renewable sources in land-use planning and for the establishment of district heating and cooling.

In 2013, the United Nations Environment Program (UNEP) conducted research on cities worldwide to identify the key factors underlying their success in scaling up energy efficiency and renewable or low-carbon energy. District energy emerged as a best practice for providing local, affordable and low-carbon energy supply. The report research found that district energy is increasingly showing up as a key strategy in both local and national plans to tackle climate change and promote public benefits such as resource recovery, energy resilience and local economic development.

In 2015, UNEP published a report based on this research entitled "District Energy in Cities: Unlocking the Potential of Energy Efficiency and Renewable Energy" which features experience and recommendations from 45 champion cities with modern district energy systems.[9] These cities are pursuing district energy to achieve GHG reductions, air pollution reductions, energy efficiency improvements, use of local and renewable resources, resilience and energy access, and green economic development. The report highlights the importance of the heating and cooling sectors to carbon and renewable energy policy, but also the relative lack of attention to these sectors in policy making to date. The report also highlights the importance and power of local governments to advance district energy, which is highly integrated with land use and other infrastructure planning. During interviews for the report, local governments were ranked as the most important actors in

9 The report is available here: http://www.unep.org/energy/portals/50177/DES_District_Energy_Report_full_02_d.pdf.

Figure 2: *Trend in Energy Use in Norway by Energy Carrier (Relative to 2000 Baseline)*



Note: Reflects heat delivered through district energy vs. direct use of other fuels. District heating in turn may be supplied via waste, bioenergy or electricity.

Source: Institute for Energy Technology. Energy Efficiency Trends and Policies in Norway. September 2015. Available at: http://www.odyssee-mure.eu/publications/national-reports/energy-efficiency-norway.pdf

catalyzing investments in thermal networks.

The UK and Norway provide particularly relevant case studies of nation-wide policy frameworks to expand thermal networks and to support local government efforts in heating and cooling. The UK has been particularly aggressive in conducting studies, establishing targets and developing plans for thermal networks. In 2013, a report for the Department of Energy and Climate Change found there is cost effective potential for heat networks to supply between 14% and 43% of total UK buildings heat by 2050 (versus 2% today), particularly in denser urban areas.[10] For the last three years, the UK Government has been providing financial and non-financial support to local authorities in England and Wales for planning and developing heat networks through a specialised unit called the Heat Network Delivery Unit (HNDU). A recent discussion paper on the future of UK heat policy from the Committee on Climate Change reaffirms the important role of thermal networks.[11] It also argues that new approaches will only be realised with strong government leadership and coordination between national and local levels.

Norway, which shares many similarities with B.C., currently has one of the fastest growing district heating markets in the world. Norway (like B.C.) has traditionally used local hydropower resources for electric heating. In 2010, Norway adopted a 10-year target to supply 16 percent of the entire national heat market with modern district energy to help reduce the use of electricity for heating and to increase the use of local renewable fuels, including energy from waste, biomass, solar and ambient energy sources (e.g., geothermal and sewer heat recovery). To achieve this goal, Norway uses a licensing framework for district energy planning, with implementation at the local level. The national government requires new district heat providers to develop a detailed plan that includes evidence of the socio-economic and environmental benefits of district heating relative to other options and then provides the license holder the validity to operate as the sole supplier of heat in a specified area, thereby de-risking investment in new networks. This enables local authorities to mandate connections, protects consumers by establishing service standards and requiring tariffs to be competitive with the next fuel/technology alternative (in this case, electric heat), and provides a level playing field

10 Report available here: https://www.gov.uk/government/u ploads/system/uploads/attachment_data/file/190149/16_04-DECC-The_Future_of_Heating_Accessible-10.pdf

11 Paper available here: https://www.theccc.org.uk/publication/next-steps-for-uk-heat-policy/

▲ *Canada lags behind the EU on targeted heat policies*

by requiring the socio-economic benefit analysis in the cost assessment criteria. Norway has also enacted a number of other policies that are key to district energy development including requiring all buildings over a certain size to use 60 per cent renewable heat, banning electrical and fossil fuel-based heating (exemptions can be claimed for passive houses); prohibiting the landfilling of organic waste (which encourages biogas production); and requiring at least 50 per cent of the energy from any municipal waste incinerator must be recovered. As a result of these policies, energy supplied from district energy networks in Norway has increased three to five-fold in the household and tertiary (commercial) sectors since 2000 (Figure 2).

1.7 FEDERAL AND PROVINCIAL CONTEXT

Canada lags behind the EU in terms of targeted heat policies, expansion of thermal networks, and coordination between federal, provincial and municipal policies on climate change. There are about 160 existing district energy systems in Canada, collectively serving approximately 2% of the national building stock. Many of these systems rely largely on natural gas. Fuel switching and expanding these systems represents an important opportunity for significant and cost-effective GHG reductions at a national scale. Overall penetration of district energy in Canada is low relative to other jurisdictions that lead in renewable and low-carbon heat. There are many more opportunities for new thermal energy systems within dense urban areas to tap low-carbon heat sources that are not viable or cost-effective at smaller scales, including substantial waste heat sources.

Neither the federal government nor the Province of BC currently have explicit policies or programs to support the development of new thermal networks or decarbonization of existing thermal systems. The federal government is actively considering opportunities to support low-carbon projects through new green infrastructure programs, but program details have yet to be confirmed. The federal government has also proposed a minimum pan-Canadian floor on carbon pricing that would help reduce the gap between the cost of conventional gas-fired heating and low-carbon heat for existing buildings. The model national energy code for buildings does not incorporate international best practices for reducing carbon emissions, increasing renewable heating, or levelling the playing field between on-site systems and off-site systems (site vs. source energy considerations).

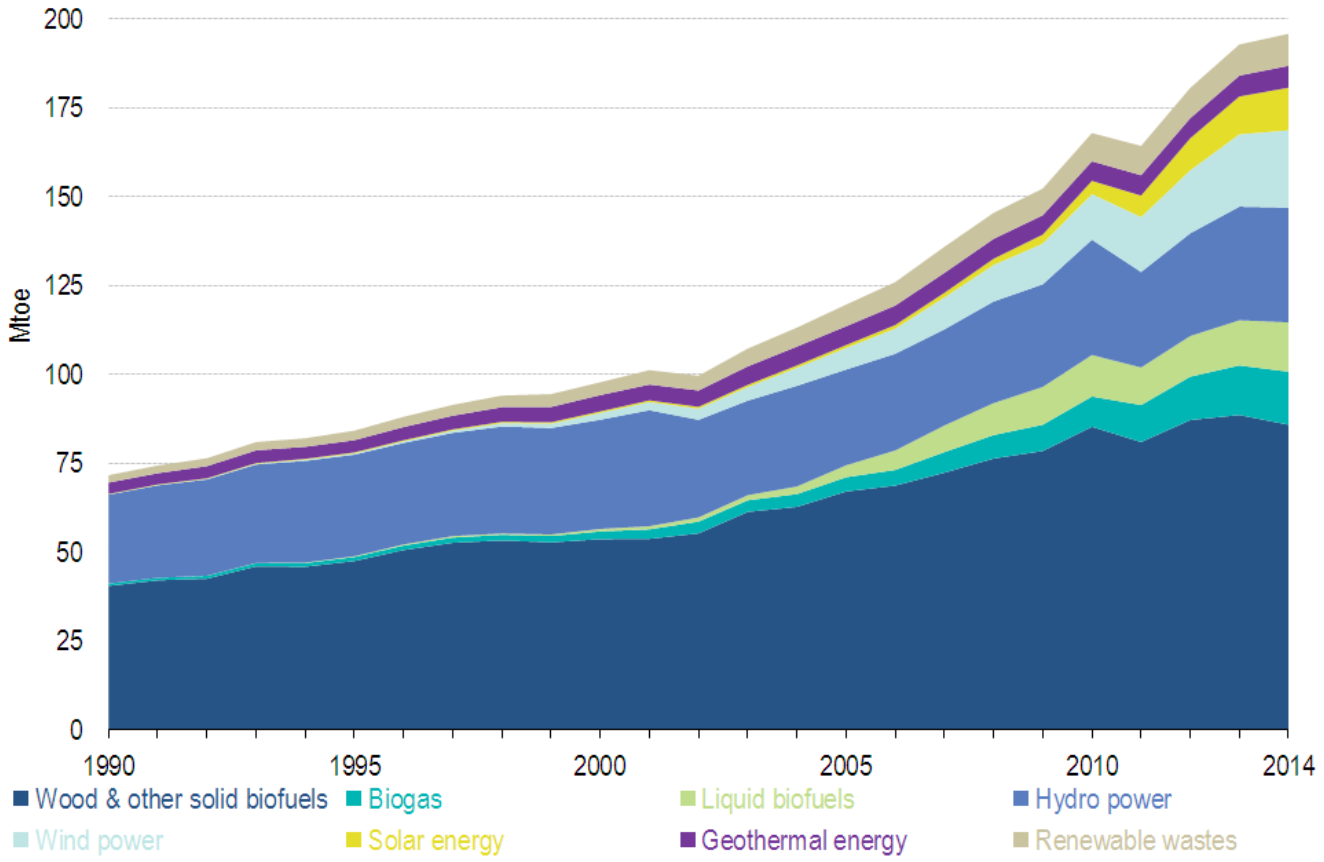
Besides potentially purchasing offsets from the Fuel Switch to support its carbon neutral government commitments, there are currently no Provincial sources of funding for this type of low-carbon energy project. The Fuel Switch project would eliminate more than 81,000 tonnes of GHG emissions, equivalent to about 16,500 cars. Current provincial incentives for an equivalent number of electric vehicles would total over $82 million. There is simply no comparative program for low-carbon heating. There are also numerous distortions in provincial policy that create barriers to cost-effective investments in thermal networks and renewable heating. These include distortions created by the provincial property tax regime (more later in this report), provincial directives that result in electricity rates that do not reflect actual costs, and buildings energy codes (including stretch codes) that do not explicitly incorporate carbon outcomes, distinguish clearly between envelope performance and equipment efficiency, or level the playing field between on-site systems (distinguish between site and source energy).

1.8 TECHNOLOGY AND PROJECT PRECEDENTS

When it comes to renewable energy, people tend to think first of wind and solar power. But around 40% of renewable energy in the EU currently comes from wood, with another 20% from hydropower (Figure 3). And much of the energy from wood goes towards heating applications.[12] As of 2013, renewable energy represented approximately 18% of primary energy for heating purposes in the European Union and biomass represented nearly 90% of the renewable energy used for heating purposes.[13] Some of the key sources of wood in Europe include local urban wood waste and forestry residues, as well as imported wood waste or pellets.

There are many global example of biomass-fired district heating projects. Some prominent precedents in urban settings are summarized in Table 1 on the following pages. Many of these systems also use other fuels including natural gas, oil and in some cases coal or municipal solid waste, however only the biomass component is discussed. The design and experience of these projects helped to inform the feasibility study for the Creative Energy Fuel Switch.

Figure 3: *Primary Energy Production from Renewables in European Union (1990-2014)*
Mtoe = million tonnes of oil equivalent



Source: Eurostat. (http://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_from_renewable_sources)

12 http://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_from_renewable_sources
13 Commission Staff Working Document. Review of available Information. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. An EU Strategy on Heating and Cooling. https://ec.europa.eu/energy/sites/ener/files/documents/SWD_2016_24_EN_autre_document_travail_service_p_v5.pdf

Table 1: *Some Precedent Urban Wood Waste Energy Projects*

ST PAUL DISTRICT ENERGY ST PAUL, MINNESOTA, USA	
Owner/Operator:	EverGreen Energy (Private, non-profit)
Biomass Capacity:	65 MWt
Output Energy:	Hot water, electricity
Biomass Fuels:	Clean urban wood waste
Biomass Technology:	Grate Furnace

This is one of the largest urban biomass CHP projects in North America. The system serves over 80% of the central business district in downtown. The network was initiated in 1983 (a conversion of a legacy steam system). Biomass CHP was introduced in 2003. EverGreen owns and operates both the plant and the wood waste yard that processes and delivers fuel to the plant. Electricity is sold to the local power company. EverGreen places a high priority on community engagement with an average of more than 100 high school students touring the facility every week. Public awareness was further enhanced recently through a public art project to illuminate the steam plume.

ENWAVE SEATTLE (FORMERLY SEATTLE STEAM) SEATTLE, WA, USA	
Owner/Operator:	Brookfield Asset Management/Enwave (Private)
Biomass Capacity:	30 MWt
Output Energy:	Steam
Biomass Fuels:	Clean urban wood waste
Biomass Technology:	Fluidized bed

The system serves approximately 200 buildings in downtown Seattle, supplying about half of their annual energy from locally sourced clean urban wood waste. The fuel switch to biomass was implemented in 2009 via a retrofit at one of the existing steam plants in close proximity to a high end hotel and residential condo developments along the Seattle waterfront. The waste wood comes from a local waste management company that delivers at night to avoid traffic congestion. The system allows buildings to meet Seattle's sustainability goals for buildings, as the wood fired heat is recognized within the city's green building policy.

Table 1 Cont'd: *Some Precedent Urban Wood Waste Energy Projects*

UBC BIOMASS DEMONSTRATION AND RESEARCH FACILITY VANCOUVER, B.C.	
Owner/Operator:	University of British Columbia
Biomass Capacity:	6 MWt
Output Energy:	Steam, hot water
Biomass Fuels:	Clean urban wood waste
Biomass Technology:	Gasification

On the basis of fulfilling the Living Lab and Carbon Neutral mandate of the University, UBC installed a biomass research and demonstration facility in 2012. The project received grants for ~70% of its capital costs (including gasifier, gas clean up system, and CHP engine). The initial system concept was to use syngas from the biomass gasification process to generate heat and power. The biogas to CHP portion of the project has since been decommissioned (due to challenges with the gas clean up system and additional capital costs that would be incurred to deal with issues). The engine has instead been converted run on natural gas, and UBC now purchases RNG for the electrical portion of the engine output in order to preserve a Load Displacement Credit from BC Hydro. UBC uses conventional natural gas for the thermal portion of the engine output. The gasifier and boiler portion of the plant continues to produce heat from biomass, supplying approximately ~20-25% of the current annual energy demands for the UBC academic system. Continuous emission monitoring is in place, data is publically available, and the system continues to meet is emissions targets.

PEI DISTRICT ENERGY CORPORATION CHARLOTTETOWN, PEI	
Owner/Operator:	Veresen Inc. (Private)
Biomass Capacity:	12 MWt
Output Energy:	Steam, hot water, electricity
Biomass Fuels:	Clean urban wood waste
Biomass Technology:	Grate furnace

The system serves residential, commercial and institutional customers in Charlottetown, PEI. The network includes a 1 km long interconnection to a hospital campus, three quarters of which is above-ground. Multiple fuel suppliers provide redundancy and competition. The system includes thermal storage (hot water).

Table 1 Cont'd: *Some Precedent Urban Wood Waste Energy Projects*

NEUKÖLLN / GROPIUSSTADT BIOMASS COMBINED HEAT & POWER PLANT BERLIN, GERMANY	
Owner/Operator:	RWE (Private)
Plant Capacity:	65 MWt; 20 MWe
Output Energy:	Heat and power
Biomass Fuels:	Forest residues and urban wood waste
Biomass Technology:	Step grate

The plant has been in operation about 12 years. The plant is part of one of the largest district heating networks in Berlin, supplying heat to over 20,000 apartments. The electricity is sold under Germany's feed-in tariffs for renewable energy. Biomass is delivered by boat on a neighbouring canal. The plant avoids approximately 235,000 tonnes of GHG emission from both heating and electricity production.

QUEEN ELIZABETH OLYMPIC PARK AND STRATFORD CITY LONDON, ENGLAND	
Owner/Operator:	ENGIE (formerly Cofely, subsidiary of GDF Suez) (Private, 40-year Concession Arrangement)
Biomass Capacity:	3.5 MWt (biomass portion of plant only; initial installation; room to expand)
Output Energy:	Heat and some cooling (via absorption chiller); power through gas-fired CHP
Biomass Fuels:	Woodchips and pulp from a variety of sustainable sources
Biomass Technology:	Grate furnace

This is one of the largest combined cooling, heating and power generating facilities built in the UK in recent years (~£100M capex). The system was initiated to provide sustainable low-carbon energy for venues and other facilities related to the 2012 Olympic and Paralympic Games. The initial energy centre is sited on the west end of the Olympic Park in the historic Kings Yard industrial buildings. This energy centre houses a natural gas-fired combined cooling heat and power unit; biomass fired boilers; natural gas-fired peaking and back-up boilers; conventional chillers; and absorption chillers. The modular design allows for future expansion. A second energy centre was also built in nearby Stratford City (serving a large mall and neighbouring development). The two energy centres are interconnected to form one integrated system (about 18 km of network in total). The energy centres have room for an ultimate capacity of up to 200 MW heating, 64 MW cooling and 30 MW electricity. About five new neighbourhoods in East London are being planned for development and interconnection in the future. There are mandated connections within a zone of exclusivity which is supported by a price control formula in the concession arrangement. The total system (CHP and biomass boiler) saves about 11,700 tonnes of GHG emissions annually, which represents about a 31% reduction over conventional generation.

Table 1 Cont'd: *Some Precedent Urban Wood Waste Energy Projects*

AVEDØRE POWER STATION COPENHAGEN, DENMARK	
Owner/Operator:	DONG Energy (Private Generator, Public Heat Network)
Plant Capacity:	918 MWt; 793 MWe
Output Energy:	Heat and power
Biomass Fuels:	Straw, wood pellets
Biomass Technology:	Varies

Unit 1 (installed in 1990) is undergoing a conversion from coal to wood pellets (target completion fall 2016). Unit 2 (2001) is able to use gas, oil, straw, and wood pellets. Plan is to convert to 100% biomass by 2027.

VÄRTEVERKEN BIOFUEL COMBINED HEAT & POWER PLANT VÄRTAN, STOCKHOLM	
Owner/Operator:	Fortum Corporation and the City of Stockholm (Public / Private Partnership)
Plant Capacity:	280 MWt; 130 MWe
Output Energy:	Heat and electricity
Biomass Fuels:	Forest residues and wood waste
Biomass Technology:	Circulating fluidized bed, back pressure turbine

The plant began commissioning in May 2016 and will start commercial production in the autumn of 2016. The plant is located approximately 2 km from downtown Stockholm. Transport of biomass fuel from the port to the power plant is provided by a 1 km-long underground conveyor. In addition to electricity, the plant produces district heat for nearly 200,000 households. With the new power plant 90% of Fortum Värme's district heating will be from renewable and recovered energy sources. Fortum Värme is the first energy company in Europe to have the Forest Stewardship Council's (FSC) Chain of Custody (CoC) certification. The new power plant will reduce emissions in the Stockholm area by about 126,000 tonnes per year.

1.9 REGULATORY CONTEXT

In British Columbia, Creative Energy is considered a public utility and is regulated by the BCUC under the Utilities Commission Act (UCA). Under the Commission's Thermal Energy System (TES) Guidelines, Creative Energy's downtown steam system is considered a Stream B utility and is therefore subject to full BCUC oversight similar to other large public utilities such as BC Hydro and FortisBC.[14]

The BCUC has broad powers over regulated utilities including:

- Approval of all utility rates (tariffs), including all terms and conditions to ensure they are fair, just and reasonable. This typically includes periodic review of the prudency of all utility capital and operating costs. In approving rates, the BCUC also approves utility financing costs, including capital structure (maximum and minimum equity requirements) and allowed return on equity.

- Approval of any new facilities and/or extensions of service or facilities. This may be through a Certificate of Public Convenience and Necessity (CPCN) for individual projects that exceed a certain size, or approval of system extension guidelines and annual capital budgets for smaller and more typical capital investments.

- Approval of any security issued by a utility, whether shares, bonds, debentures, noted or any other obligation of a public utility (secured or unsecured) exceeding one year.

- Approval for any consolidation, amalgamation, or mergers of utility corporations, the sale of utilities, and any sale or disposal of major assets.

- Review and approval of major supply contracts.

- Review and approval of any privilege, concession or franchise granted to a public utility by a municipality or other public authority.

- Set standards and review service quality.

As a regulated public utility, Creative Energy's Fuel Switch project would be open book. All costs would be reviewable by the BCUC, including financing costs. Since regulated utilities only earn a fixed rate of return based on net capital investment, any financial consideration provided by the City, the Province or the federal government would go to the benefit of customers via lower rates.

Creative Energy cannot begin to construct or operate the Fuel Switch without first obtaining a CPCN confirming the project is in the public interest, as required by section 45(1) of the UCA. Normally a utility would not complete detailed design and tendering prior to a CPCN because it may not be able to recover these costs if the CPCN is not approved. As a result, the CPCN process is an important part of the development timeline for the Fuel Switch. A CPCN application could add 9 – 12 months to the overall development timelines for the Fuel Switch. The Commission has developed CPCN Guidelines for applicants, which outline general expectations for a CPCN.[15] This feasibility study provides a critical foundation for the CPCN application. However, as outlined later in this report, further due diligence, consultations and negotiations will be required prior to submission of any CPCN application for the Fuel Switch project.

For existing utilities, a CPCN application for major capital projects is typically informed by a long-term resource plan (LTRP). The UCA requires energy utilities to file an LTRP with the BCUC. An LTRP sets out a long-term load forecast and a plan to meet that forecast, which may include a mix of supply-side resources, and demand side management programs. Creative Energy's

14 The TES Guidelines are available here: http://www.bcuc.com/Documents/Guidelines/2015/DOC_42213_TES-Guidelines.pdf

15 The CPCN Guidelines can be found on the BCUC website at: http://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf
The BCUC has also provided additional guidance for TES utilities and providers as part of the TES Guidelines. However, many of these requirements are already reflected in the general guidelines and some requirements are more relevant to new greenfield utilities, as opposed to an established utility seeking approvals for a new supply project.

predecessor (Central Heat) was never required to file a LTRP in the past. This was likely because of its small size and unique circumstances. However, in its decision regarding Creative Energy's 2015-17 Revenue Requirement Application (Order G-98-15), the Commission directed Creative Energy to submit an LTRP prior to making an investment decision regarding a low-carbon Fuel Switch that may impact the existing steam customers and in any event no later than June 2017.

Under sections 59-61 of the UCA, Creative Energy will also need formal approval from the Commission for any changes in Creative Energy's existing rates (or any new rates contemplated) arising from the Fuel Switch project. A full rate application may come after the CPCN application. However, the CPCN application will need to provide a reasonable level of information on expected impacts on customer rates for the Commission to determine if the project is in the public interest.

1.9.1 Commission Decision on NEFC Neighbourhood Energy Agreement

Under Section 45(7) of the UCA, the Commission must also approve any privilege, concession or franchise granted to a public utility by a municipality. When the feasibility study for the Fuel Switch was initiated, Creative Energy and the City were in discussions for a new franchise agreement in NEFC (the Neighbourhood Energy Agreement or NEA) that would help secure additional loads for the larger Fuel Switch. Creative Energy and the City had also expected to replicate this agreement for South Downtown and elsewhere in Vancouver. NEFC and South Downtown were considered in establishing a target size of the Fuel Switch in this feasibility study. These customers provide not only additional economies of scale but also revenue security given formal carbon performance requirements and connection policies. As a result, these neighbourhoods help to reduce any financial gap for the Fuel Switch project before other optimizations or enabling strategies. As discussed later in this feasibility study, there are many other new to loads that could reduce the financial gap even further.

In a typical real estate development, the selection of the energy systems to supply hot water and heat to end-use customers, as well as ongoing ownership and operating model, is made by the developer. Municipalities have observed, as have many others, that developers' choices are not always in the public interest due to split incentives, unpriced externalities or public goods, and conflicting policies, among other factors. Further, the ability of consumers to weight energy costs, or to influence developers' selection of energy systems (particularly in multi-family or multi-tenant buildings) is limited by information asymmetries, greater importance of location considerations, and supply constraints, among other factors. Finally, staged decision making in the face of uncertain timing and sequencing development can hinder the development of larger networks and low-carbon energy sources with economies of scale and integration. For these reasons, often after lengthy public consultation processes, some municipalities have established connection policies to support development of low-carbon thermal networks.

Since the completion of this feasibility study, the Commission granted a CPCN for the hot water network in NEFC, but rejected the proposed NEA for NEFC between the City and Creative Energy.[16] The NEA for NEFC established requirements for a new neighbourhood-wide hot water network together with neighbourhood-wide carbon performance requirements. These performance requirements were deferred to allow Creative Energy to pursue the most optimal scale and timing of projects for the neighbourhood as a whole. Because of uncertainty in the actual timing and pattern of development, the City also agreed to establish connection policies that would provide security for any investments in the hot water network. Because of these connection policies, the NEA would also have provided some

16 There are three significant decisions in relation to NEFC (collectively referred to as the NEFC Decisions) found in Order C-12-15, Order G-88-16, and Order G-151-16. The initial decision included feedback from the Commission Panel on specific clauses it took issue with. The parties negotiated an amended agreement and submitted it for approval. This amended agreement was also rejected by the Commission. The second decision also included reasons not raised by the initial Panel.

immediate revenue security for the larger Fuel Switch.

The vision for NEFC was modelled on neighbourhood energy systems approved by the Commission for master-planned communities at Simon Fraser University, the University of British Columbia, Dockside Green in Victoria, and River District in Vancouver. For these systems, investments are secured by agreements between private utilities and a single master developer (sometimes the utility and the developer are one and the same). In the case of NEFC, which has multiple landowners, the City's connection policies were modelled on similar ones established for municipally-owned systems in mixed ownership neighbourhoods in Vancouver, North Vancouver, Surrey, and Richmond among others. The goal of the NEA was to leverage the expertise and capital of private regulated utilities to achieve outcomes comparable to municipally-owned systems.

In the NEFC Decisions, the Commission found that a neighbourhood-scale hot water network for NEFC was in the public interest (the Commission was not asked to consider the ultimate low-carbon energy source as part of the CPCN application), but paradoxically the Commission rejected municipal connection policies intended to secure that outcome. The Commission seems to be of the view that developers should have broad authority to determine what energy systems and thermal networks are in the public interest, but municipalities should not. The Commission also appears to place little weight on achieving economies of scale in thermal networks or low-carbon energy sources, and did not acknowledge any role for municipal policies in securing the benefits of scale in neighbourhoods with very uncertain timing and sequencing of development.

The consequences of the NEFC Decisions are significant. First, in the absence of other enabling strategies, it is unlikely that significant new thermal networks will be developed in B.C. by investor-owned utilities within mixed-ownership neighbourhoods. Second, while the NEFC Decisions do not alter the consumer or environmental benefits of the Fuel Switch project, they have now increased the investment risks and financial gap in the absence of other enabling strategies. Third, given the City's commitment to renewable energy, GHG reductions and neighbourhood energy the City will now need to consider other options to secure loads or otherwise enable new thermal energy networks and larger low-carbon projects such as the Fuel Switch. The City is actively exploring its options.

1.10 MARKET DRIVERS AND CONSTRAINTS

One of the greatest challenges for the Fuel Switch is load/revenue security. The Fuel Switch is one of the least-cost sources of low-carbon energy for downtown. However, it is still costlier than conventional gas-fired energy under current gas and carbon price forecasts.

New development in Vancouver has formal carbon performance requirements, this creates a different cost benchmark for new customers. Prior to a recent Commission decision on NEFC (see above), Franchise agreements and associated connection policies were expected to secure revenues from future developments in NEFC and South Downtown to support investments in new networks and reduce investment risks for the larger Fuel Switch. Under the base case assumptions in this study, about 17% of the Fuel Switch output is allocated to new development in NEFC and South Downtown. However, there is considerable other development potential downtown and elsewhere in Vancouver that could help to secure an investment. There are also other existing gas-fired buildings downtown that are compatible with district energy but not yet connected to Creative Energy.

Unlike new development, existing buildings and steam customers have no formal carbon performance requirements. Gas-fired steam from Creative Energy's existing plant is the relevant benchmark for existing customers. Under the Province's carbon neutral government commitments, Public Sector Organizations (PSOs), which include schools and hospitals, also incur an additional cost of about $10 / MWh to offset emissions from gas-fired steam (over and above the carbon tax included in Creative

Figure 4: *Remaining Contract Term of Existing Steam Customers*

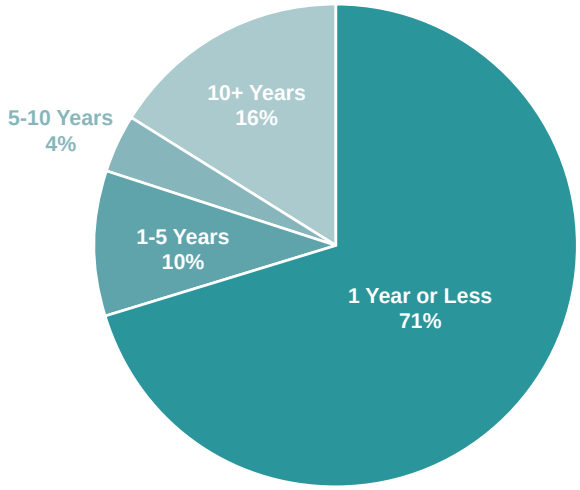
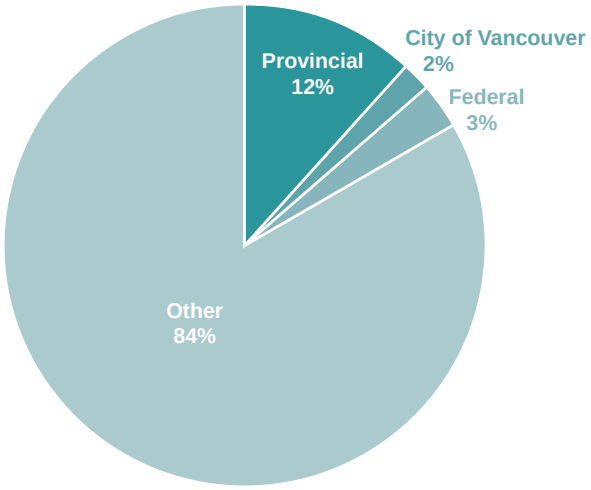


Figure 5: *Existing Steam Sales to Government-Controlled Buildings*



Energy's steam rates). The current price of offsets is based largely on low-cost forest sequestration projects. PSOs represent about 12% of Creative Energy's existing customer base.

Initial development and ongoing extension of Creative Energy's steam system was originally secured with long-term customer contracts. The majority of existing customers are now on month-to-month contracts (Figure 4). Creative Energy's ability to raise rates for these customers to support a large and discretionary project such as the Fuel Switch (>$120 million in direct capital costs) is limited. Any increases would need to be approved by the Commission. Even if these increases were approved, existing customers could still switch to on-site gas boilers, stranding the investment in the Fuel Switch. Creative Energy will require long-term contracts to secure such a large and discretionary investment as the Fuel Switch, particularly if there is an expected premium over status quo energy costs for existing customers. Currently, Creative Energy expects to run a subscription process for existing steam customers prior to a final investment decision. This subscription process would confirm long-term customer commitments and any willingness to pay a premium for low-carbon energy.[17]

In-depth interviews and less formal conversations as part of this feasibility study suggest some willingness among large commercial customers to pay a premium for low-carbon energy in order to meet corporate commitments for GHG reductions and renewal energy, or recertify buildings (for example, to LEED Gold) in order to attract tenants with corporate commitments. Customers may also be willing to pay some premium simply to reduce their financial exposure to uncertain and volatile gas, carbon and/or offset prices, since the bulk of the cost of energy from the Fuel Switch would be fixed once the plant is constructed. Creative Energy anticipates that small commercial customers and residential stratas will be more price sensitive than larger customers in the absence of formal carbon performance requirements or other incentives. For residential stratas, there is some added complexity posed by requirements for collective purchase decisions by strata councils and/or all strata members.

17 For comparisons, investors in new green power or renewable natural gas projects in B.C. do not take volume or price risk. Further, the scale of individual energy supply projects/contracts or individual network extensions pales in comparison to the scale of existing gas and electricity networks or customer numbers. These networks, in turn, were developed under very different market conditions and with considerable public policy support in the past.

The City, Province and federal government collectively control about 17% of existing steam customers (Figure 5).[18] Creative Energy expects government will demonstrate leadership through formal commitments of government buildings to the Fuel Switch project. The feasibility study also considers opportunities to sell offsets to the Province for any GHG emissions allocated to existing steam customers. This could help to secure the initial investment while reducing any near-term premium for existing customers.

Creative Energy does not anticipate that a voluntary subscription process alone will be sufficient to offset a significant financial gap under current market conditions and in the absence of other enabling strategies. Creative Energy does not intend to undertake a costly subscription process until it has confirmed key project inputs and other enabling strategies. These include details for the lease of the target site from the City; the availability of other City financial enabling tools; the availability of grants and/or other financing options tied to gas and carbon prices; the possibility of offset sales to the Province, and the possibility of other new customers that would reduce the required volume and/or premium for voluntary subscriptions. Before commencing a voluntary subscription process, Creative Energy would also hope that governments will provide more information on likely future carbon policies or prices for existing buildings to help inform long-term customer decisions.

18 There are examples of other government buildings not yet connected to district energy downtown which could also show climate leadership through connection to the Fuel Switch. For example, Canada Place, which is operated by Port Metro Vancouver (an arm of the federal government), is located adjacent to Creative Energy's existing steam network. Canada Place is currently heated by a large and aging on-site gas-fired steam plant. The current steam demands for Canada Place represent about 3 - 5% of the total demand on Creative Energy's existing steam network.

1.11 ORGANIZATION OF THIS REPORT

This report summarizes the results of two years of study, including dozens of scenarios for the project. The report is organized as follows:

Section 2 summarizes the study methodology, including the key steps and timelines for the study.

Section 3 summarizes the process used to select a preliminary site for the plant to support the detailed feasibility study.

Section 4 summarizes the interconnection study conducted to assess the cost of connecting the preliminary site (and several alternative sites) to the existing plant and steam system. This section also summarizes some of the technical issues for the interconnection and opportunities for reducing the interconnection costs.

Section 5 summarizes the proposed technology, including performance and cost assumptions. As described in this section, the technology selection was informed by an international Request for Information from technology vendors.

Section 6 summarizes the results of research on available supply and prices for clean urban wood waste. As described in this section, the fuel research was also informed through a Request for Information from local aggregators and follow up discussions with the industry.

Section 7 describes the site concept and preliminary design of the building to house the plant, referred to as the Green House, including site context, zoning and transportation considerations. This section also includes a discussion of the proposed rooftop farm and interpretative centre.

Section 8 presents the base case financial and GHG analysis for the Fuel Switch project before any optimizations or other enabling strategies. This section includes a projected cost of service; avoided costs of gas-fired steam (status quo); preliminary financial gap (before optimizations or enabling strategies); rate impacts under base case assumptions; sensitivity analyses on base case inputs; and projected GHG reductions.

Section 9 examines possible optimizations and various enabling strategies to address the financial gap, including alternate allocations of energy and GHG emissions and voluntary subscription process, grants, offset sales, and other City financial enabling tools.

Section 10 examines various project alternatives and rate comparators for existing and new customers. This section also includes an analysis of the implicit carbon abatement cost of the Fuel Switch and other alternatives.

Section 11 summarizes the preliminary air quality assessment conducted for the project (detailed report provided under separate cover).

Section 12 summarizes the potential contribution of the project to the Province's Clean Energy Objectives.

Section 13 summarizes consultations to date including the results of preliminary in-depth stakeholder interviews.

Section 14 discusses implementation issues and next steps.

Some additional Engineering Drawings and Schematics are provided as attachments to this report. There is also additional detail on the hot water conversion alternative attached to this report. The various financial analyses contained in this report were prepared using a detailed excel model. This model is held in confidence because it contains commercially sensitive information.

There are a number of separate stand-alone reports that consolidate the results of other supporting studies including:

- a preliminary air quality assessment prepared by Levelton,
- a summary of in-depth stakeholder interviews prepared by Ipsos, and
- a quantity surveyor report on the expected cost for the preliminary building design.

2. STUDY METHODOLOGY

2.1 BUILDING ON PAST STUDIES

This study builds on the two previous screening studies completed in 2010 and 2012. Those studies helped to frame the project concept, narrow feasible technologies, and establish some of the starting inputs for this feasibility study. Some examples of refinements / updates in the current feasibility study include:

- Selection of a specific target site for the plant to inform land costs, interconnection alternatives/costs, and site concepts/building costs (including compatible uses, aesthetic considerations, and traffic flow); and to explore other implementation considerations.
- Review and confirmation of Creative Energy's existing heating load duration curve, which affects the expected annual energy contribution from different sizes of plant.
- Updates to the avoided costs of steam generation from the existing Beatty Street plant including updated assumptions for the fuel efficiency of the existing plant.
- Estimates (conservative) for possible mandatory low-carbon customers / neighbourhoods to support the larger Fuel Switch project.
- Additional review of project alternatives and estimates of other low-carbon thermal energy benchmarks.
- Updated fuel price forecasts, including validation of expected prices for urban wood waste. Wood waste prices were informed by additional research and the results of a Request for Information (RFI) from possible fuel providers.
- More refined technology options, costs and performance assumptions including:
  - sizing assumptions for the project, and
  - refined capital costs and performance assumptions (e.g., fuel efficiency assumptions) obtained through a global Request for Information (RFI) from technology vendors based on the target specifications, with some additional information on alternative specifications.
- More detailed estimates of incremental staffing requirements for the Fuel Switch, as well as integration issues with existing Beatty Street plant operations.
- Analysis of additional project design optimizations including phasing options and CHP alternatives.
- More detailed assessment of project drivers, barriers and enabling strategies.
- Consideration of other project impacts and benefits, including a preliminary air quality assessment.
- Preliminary stakeholder consultations (in-depth interviews with a sub-set of existing customers, potential new customers and community stakeholders).

2.2 WORKPLAN

The feasibility study was initiated in January 2014 following award of a grant from the Federation of Canadian Municipalities (FCM) Green Municipal Fund. Some key study milestones are shown in Table 2. The study was led by Reshape Infrastructure Strategies (Reshape) with support from a wide range of specialties. A complete list of contributors is provided in the Acknowledgements section of this report.

The work plan was organized into the following key tasks:

- Site selection / building concept
- Interconnection study
- Generation technology assessment
- Fuel supply assessment
- Air quality assessment
- Preliminary stakeholder consultation (in-depth interviews)
- Pro forma analysis (costing of project inputs; base case cost-of-service and outcomes; assessment of project alternatives; preparation of other low-carbon energy benchmarks)
- Analysis of project risks, uncertainties optimization, enabling strategies and implementation considerations
- Reporting

There was iteration among these tasks to refine and optimize the base project concept, input assumptions and results. The length of the study was due in part to the time required to stage individual tasks, as well as to provide time for two separate Requests for Information (RFIs), one for the steam generation technology and one for fuel supply. This included preparing and issuing each RFI, allowing time for vendors to respond, vetting responses (including interviews with some proponents), and incorporation of results into other study tasks. The technology RFI was completed first to inform the subsequent fuel RFI. The original timeline was also intended to allow for input from the City on input assumptions, model outputs, optimizations and enabling strategies.

This feasibility study was informed by the direct experience of team members in a variety of relevant projects, including site visits and research undertaken specifically as part of the work plan for the current study. Some examples include:

- District Energy St. Paul (Minnesota)
- Seattle Steam
- Richply biomass plant (Richmond)
- University of British Columbia's Bioenergy Research and Demonstration Project
- Kruger's New Westminster paper mill
- Charlottetown district heating system (Prince Edward Island)
- Site visits to several major European biomass projects since 2011 including projects in the UK (London Olympic Park, Tottenham Hale Village), Germany (Berlin, Hamburg, and Munich regions); Austria (Salzburg region); Italy (Stadtwerke Brunek), Denmark (Copenhagen region); and Sweden (Lund/ Malmo region).

The project team also visited Lufa Farms' two existing rooftop farms in Montreal to conduct due diligence on the concept for the rooftop farm.

Table 2: *Some Key Study Milestones*

DATE	MILESTONE
January 23, 2014	FCM Award
May 15, 2014	Site Selection and Interconnection Study Complete
August 8, 2014	Technology RFI Issued
October 8, 2014	Technology RFI Closed
January 14, 2015	Fuel RFI Issued
February 27, 2015	Fuel RFI Closed
March 3, 2015	Concept Architecture Completed
June 1, 2015	Air Quality Study Completed
July 6, 2015	Project Information Document (PID) Submission to BC Climate Investment Branch
August 15, 2015	Quantity Surveyor Report on Building Concept
November 1, 2015	Preliminary Public Engagement Report Completed
December 31, 2015	Draft Report
January – December, 2016	Additional Consultations with External Stakeholders; Discussions of Project Enabling Strategies with City, Province and Federal Government
December, 2016	Final Report

2.3 STUDY METHODOLOGY

Key features of the study methodology are summarized below.

Technical Inputs

- System concepts and performance assumptions are drawn from previous screening studies, project precedents, literature, team experience, and responses to the technology and fuel RFIs.

- Technical advisors were consulted on all system concepts, technical assumptions, potential optimizations and implementation issues or strategies.

- The detailed methodology for the air quality assessment is described in a separate report.

- For the purposes of the feasibility study, the GHG emission factor for urban wood waste is assumed to be zero.[19] This is generally consistent with local and international best practices, methodologies and standards for urban wood waste. Under B.C.'s best practices methodology for quantifying GHG emissions, public sector organizations are still required to offset direct emissions of CH_4 and N_2O from biomass fuels.[20] These factors translate to about 2.2 kg of CO_2-equivalent emissions per GJ of wood fuel (assuming 50% moisture content). This is equivalent to about 4% of the current emission factor for natural gas (based on burner-tip emissions of natural gas only). However, these emissions factors do not differentiate among different types of wood fuel (e.g., urban wood waste vs. forestry residues vs. energy plantations), or account for avoided emissions from alternative disposal methods for urban wood waste. There are also potential emissions associated with the transport of urban wood waste. However, as discussed later in this report, emissions from transportation of wood fuel represent less than 1% of the emissions avoided by use of wood waste, even before taking into account any transportation emissions avoided from alternative disposal methods or uses for local wood waste.

- The current GHG emission factor for electricity in B.C. is very low but still greater than zero.[21] For simplicity, the emission factor for electricity is assumed to be zero. This applies to electricity used in the existing Beatty Street plant, as well as electricity used in the new Fuel Switch plant. The Fuel Switch would result in a small net increase in electricity consumption relative to status quo, though overall electricity use is still very small relative to total gas and wood waste consumption in all scenarios. This electricity emissions factor also applies to the electric alternatives considered in the report. The use of a zero emissions factor for electricity likely results in a slight underestimation of the benefits of the Fuel Switch compared to other electric alternatives.

- Consistent with current provincial methodologies, the emission factor for natural gas (which is the primary determinant of the GHG benefits for the Fuel Switch) is 49.87 kg/GJ. However, this emission factor is based only on the point source emissions from burning natural gas. It does not consider any upstream emissions associated with drilling, extracting, cleaning and transporting nor does it account for the global warming impact from methane leakages, which have 22 to 100 times the warming impact of carbon dioxide (depending on the time period considered). One of the recent recommendations of the Province's Climate Action Team was to have these upstream emissions included in the carbon intensity used to calculate the carbon tax. While there is uncertainty over methane leakage rates, several studies suggest the

19 The GHG neutrality of biomass fuels is discussed further in the body of this report, including reference to specific standards.
20 http://www2.gov.bc.ca/assets/gov/environment/climate-change/policy-legislation-and-responses/carbon-neutral-government/measure-page/2016-2017_bc_best_practices_methodology_for_quantifying_ghg_emissions.pdf
21 In 2016 the emission factor for electricity in B.C. was approximately 11 tonnes / GWh. However, this emission factor is only for domestic production and does not currently account for the effects of international or interprovincial trade with jurisdictions that have much higher average emission factors.

leakage rates could be as high as 12%.[22] One recent study shows that leakage rates may be much higher for unconventional sources of natural gas (i.e., shale gas), which form a large and growing portion of B.C.'s natural gas supply.[23] In 2015, 80% of BC's natural gas production was unconventional. A low-end estimate for conventional natural gas that includes upstream GHG emissions is 85 kg/GJ (versus the emission factor of 49.87 kg/GJ based on burner tip emissions only). Using the low-end emission intensity of conventional natural gas from this study, the GHG savings from the Fuel Switch would increase more than 30%. The savings would be even higher if upstream emission factors for unconventional gas were considered. A high-end estimate for unconventional gas is 380 kg/GJ. For the purposes of the sensitivity analyses, the study team used a mid-estimate of emissions intensity for both conventional and unconventional gas, respectively, and assumed a 20/80 average blend of conventional and unconventional gas consistent with total production in B.C. This yielded an upper emission intensity of 240 kg/GJ for sensitivity analysis.

Energy Units and Measurements

- To simplify comparisons, all power (peak capacity) and energy units are provided in common metric units of megawatts [MW] and megawatt-hours [MWh], respectively.

- Steam production and use are commonly reported as mass (lbs) and mass flow rate (lbs/hr). The total energy content of steam produced at Creative Energy's plant is 0.351 MWh per 1,000 lbs (k lbs). When converting Creative Energy's retail rates from $/lb to $/MWh, an allowance has been made for average customer losses in steam to hot water converter stations. This allows an apples-to-apples comparison of steam rates to newer hot water rates and also electricity prices (electric resistance heating).

- Natural gas is commonly measured and priced in other units. Conversion factors are as follows:
  - 1 MWh = 3.6 GJ. A price of $10 per MWh is equivalent to $2.78 per GJ.
  - 1 MWh = 3.41 mmBTU. A price of $10 per MWh is equivalent to $2.93 per mmBTU.
- Biomass fuel is commonly measured and priced in Bone Dry Tonnes (BDT). Based on a typical higher heating value (HHV) of wood of 19.7 MJ/kg, 1 BDT of wood fuel = 5.5 MWh (fuel input, before conversion losses in producing steam or hot water). A biomass fuel price of $100 per BDT is equivalent to ~$18.2 per MWh.

- The heat generation capacity of the Fuel Switch plant (and all other alternatives) is measured at the plant gate. That is, reported capacity is net of internal losses for plant processes such as deaeration and blowdown.

- The Beatty Street plant is used as the point of reference for comparing status quo and the Fuel Switch. The quantity of energy displaced from the Fuel Switch and the cost of service for the Fuel Switch both reflect expected energy losses between the Fuel Switch plant and the Beatty Street plant.

Cost Inputs

- Capital costs, fuel requirements, and other maintenance and operating costs are drawn from previous screening studies, project precedents, literature, team experience, and responses to the technology RFI. The base case analysis reflects realistic design assumptions. Alternate assumptions, including potential additional optimizations which require more due diligence or external agreements, are considered in additional sensitivity and scenario analyses.

- Capital costs for the Fuel Switch plant are also informed by the site selection, interconnection

22 See for example, Turner, A. J., D. J. Jacob, J. Benmergui, S. C. Wofsy, J. D. Maasakkers, A. Butz, O. Hasekamp, and S. C. Biraud (2016), A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observations, Geophys. Res. Lett., 43, 2218–2224.

23 "Methane emissions and climatic warming risk from hydraulic fracturing and shale gas development: implications for policy", Robert W Howarth, Energy and Emission Control Technologies, 2015, p 49.

▲ *Interior of 720 Beatty Street plant*

study, and a preliminary site concept / architecture. Building cost estimates were developed with reference to other building benchmarks and consultation with a quantity surveyor.

- Biomass fuel prices (and availability) are derived from the results of the fuel RFI, other recent studies, and discussions with existing plant operators and other industry stakeholders, including the City and Metro Vancouver. Price assumptions reflect fuel specifications developed through analysis of the responses to the technology RFI and consultations with other industry experts. Ranges were developed around the expected values used for the base case to support additional sensitivity and scenario analysis.

- Natural gas prices are based on relevant delivery charges from FortisBC and commodity price forecasts from Sproule. Delivery rates are assumed to escalate at inflation. Additional gas price scenarios were derived from the Northwest Power Planning Council (U.S.), National Energy Board (NEB), and U.S. Energy Information Administration.

- Use of renewable natural gas (RNG) within the existing steam plant is considered as an alternative for the Fuel Switch. The amount of RNG that would be required to achieve the same outcome as the Fuel Switch is quite large in relation to FortisBC's existing supply pool. For the purposes of this study, the Fuel Switch is compared to a range of assumptions for the long-run acquisition costs of new RNG supply (i.e., ignoring sunk program costs, deferrals or cross-subsidies from non-participants).

- Electricity price forecasts reflect current prices, announced changes for the remainder of the government's 10-year rate plan, and 3% nominal (1% real) escalation beyond the current rate plan (starting 2020). No further allowance is made for recovery of existing deferral accounts or potential cost pressures from major new capital projects or system renewal. Electricity rate forecasts reflect

the combined effect of demand and energy charges (depending on the relevant tariff), the effects of stepped rates where relevant, and riders.

- Existing carbon taxes (and offset prices for PSOs) are used for the base case analysis. Additional scenarios for carbon taxes were drawn from recent federal proposals, the recommendations of B.C.s' Climate Leadership Team (CLT) and independent studies of marginal abatement costs to achieve Canada's long-term reduction targets.[24]

- All other operating and maintenance costs are assumed to escalate at general inflation.

- Staffing assumptions for the Fuel Switch reflect a conservative assumption of staffing synergies between the existing Beatty Street plant and new Fuel Switch plant. Additional synergies may be possible but will require consultation with the BC Safety Authority. These potential additional synergies are considered in sensitivity analysis.

- Unless otherwise noted:
  - All capital cost inputs are in $2014. These are then escalated within the financial model.
  - The design and costing effort is consistent with an AACE Class 3 cost estimate.[25]
  - Base capital cost inputs are exclusive of contingency, GST and PST. Contingency and PST are added inside the financial model. The levels of contingency vary for different project elements, commensurate with the level of design and due diligence. GST is excluded from capital cost estimates because of offsetting input tax credits.
  - All model outputs are in nominal dollars (i.e. including inflation).

Financial and Economic Analysis

- The foundation of the feasibility study is a pro forma model that calculates the annual cost of service for the Fuel Switch project from the perspective of Creative Energy and its customers under various input assumptions and scenarios.

- The annual cost of service reflects all operating and capital costs for the project before any enabling strategies or further optimizations. Capital costs are captured as annual depreciation and financing costs. Financing costs reflect Creative Energy's weighted average cost of capital (WACC), which is based on Creative Energy's current regulated capital structure, current return on equity, and a forecast of Creative Energy's long-term debt rate (slightly above Creative Energy's existing debt rate). The cost of service also includes property taxes and income taxes (including effects of relevant capital cost allowances for this project).

- The cost of service for the Fuel Switch includes the cost of the interconnection and energy losses for delivery to the existing steam plant at Beatty Street. This plant acts as the distribution centre for the existing steam network and is the reference point for avoided costs from the Fuel Switch project.

- The study uses a 30-year analysis period, which is the expected life of the mechanical equipment for the plant. Depreciation rates for the building and interconnection are somewhat longer. As a result, there is a small amount of undepreciated capital costs at the end of the analysis period.

- All present values, levelized costs and levelized rates in this report are calculated using Creative Energy's forecast after-tax WACC (5.95%).

24 The federal government has recently proposed a low-carbon fuel standard for home heating fuels such as natural gas. From the perspective of the Fuel Switch a low-carbon fuel standard for natural gas would have a comparable effect to a carbon tax since it would raise the underlying price of natural gas. For example, a low-carbon fuel standard of 15% would increase the levelized cost of gas and carbon taxes in the Fuel Switch model by 24%, all things being equal, assuming the standard is met with RNG at a marginal cost of $14 / GJ. This would also require a substantial increase in RNG production in the province.

25 The Technology RFI requested vendors to provide a Class C level of cost estimates per Association of Professional Engineers and Geo-Scientists (APEGBC) Guidelines, which is considered equivalent to AACE Class 3.

- The study assumes an in-service date for the Fuel Switch project of 2020. This was a reasonable working assumption when the feasibility study commenced. This date is also consistent with targets in the City's GCAP, Renewable Energy Strategy and the NEFC Neighbourhood Energy Agreement. However, this is no longer a realistic in-service date given the current status of project development and the critical path for negotiation of enabling agreements, customer subscription process, CPCN approvals, detailed design, tending and construction. The expected in-service depends on other parties such as the City. An actual in-service date between 2020 and 2022 is not expected to have a significant impact on the financial projections or issues in this feasibility study.

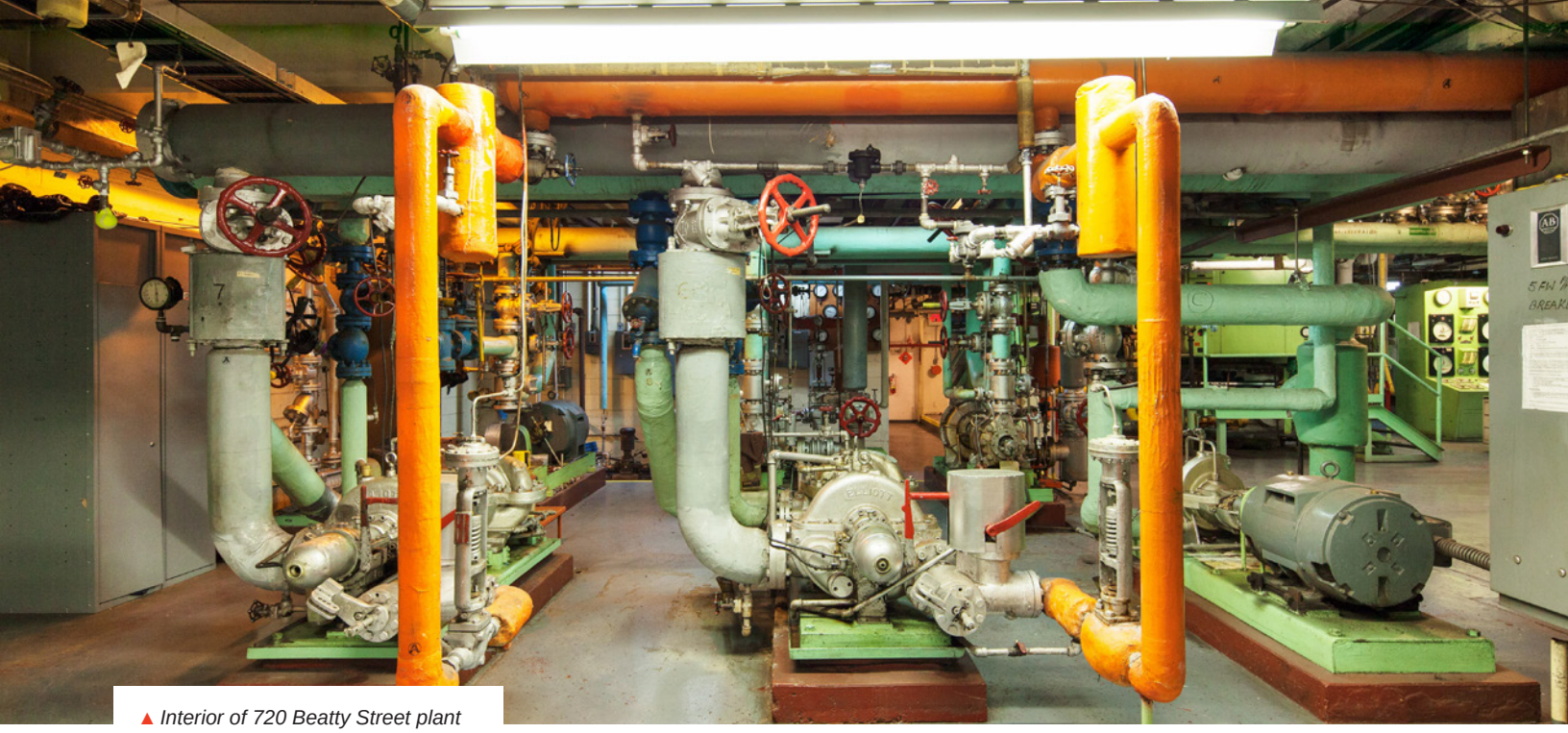
- The study compares the cost of service for the Fuel Switch to other project alternatives, including alternatives to the larger Fuel Switch and also smaller projects to serve only specific neighbourhoods.

- The study also compares the implied levelized costs of carbon abatement from the Fuel Switch with the cost of carbon abatement from other project alternatives, with existing and proposed carbon taxes, with existing PSO offsets costs, and with the expected marginal costs of carbon abatement from various studies to meet Canada's reduction targets. Carbon abatement costs are calculated as the present value of the premium for each alternative relative to conventional gas-fired steam at Creative Energy's existing steam plant (under base forecast of gas prices before carbon taxes) divided by the present value of GHG reductions relative to Creative Energy's existing steam plant.

- The study also presents all results from the perspective of retail customers. Forecasts of steam and hot water rates are estimated under both the status quo (gas-fired steam) and alternative supply scenarios. These rate calculations also include the costs of distribution and peaking energy, which are common across all alternatives. Retail rates for each scenario are compared to forecast rates for other low-carbon energy benchmarks in the region.

- The study makes a distinction between existing steam customers and proposed new hot water customers (e.g., NEFC and South Downtown). When this feasibility study was initiated, Creative Energy expected that new development in NEFC and South Downtown would be secured (for an initial period of 30 years) through franchise agreements with the City and that these franchise agreements would include carbon performance requirements supported by connection policies. For any of these neighbourhoods (or any other potential new customers), the analysis assumes customers would pay the full cost of service for any energy required from the Fuel Switch to meet carbon performance requirements. To test the viability and desirability of the Fuel Switch for these customers, the analysis compares retail rates under the Fuel Switch with rates under other project alternatives and with other low-carbon benchmarks. The financial analysis in this study assumes no revenue gap or additional investment risk for new customers (beyond normal forecast risks and prudence review assumed by utilities). The recent NEFC Decisions have not altered the cost-effectiveness of the Fuel Switch project from the perspective of these end users, but these decisions have increased investment risk in the absence of other enabling strategies.

- For existing customers, the base analysis compares of the cost of service for the Fuel Switch with the avoided costs of gas-fired steam from the existing plant. The existing steam plant is sunk and in good condition. Existing customers have no formal carbon performance requirements, and most of these customers have rolled over to short-term contracts. The investment risk of any Fuel Switch for existing customers (before other enabling strategies) is represented as the present value difference between the forecast cost of service for the Fuel Switch and the forecast avoided cost of gas-fired steam.



▲ *Interior of 720 Beatty Street plant*

Given the Fuel Switch is costlier than gas-fired steam from the existing plant under current gas and carbon prices this gives rise to a financial gap. This gap assumes no additional risks from attrition of existing customers under status quo rates (a reasonable working assumption given historic trends).

- The largest driver of the financial gap for existing customers is future gas and carbon prices. These are very uncertain. The feasibility study also includes a risk profile around the financial gap reflecting different gas and carbon price assumptions.

- Given the discretionary nature of the Fuel Switch for existing customers and the unusual form/level of investment risk, a key task in the feasibility study is to identify and evaluate strategies that would reduce the financial gap and investment risk for the project. These include design optimizations that lower the cost of service for the project, a subscription process to secure a price premium from existing customers, alternate allocations of energy and GHG emissions from the project, external offset sales, recoverable or non-recoverable grants, and various financial enabling tools that could be deployed by the City.

Levelized Costs / Rates

- The report frequently uses levelized unit costs or rates ($/MWh) for comparison purposes. Levelization is a technique for converting a forecast of values over time into an equivalent constant value taking into account the discount rate. A levelized value yields essentially the same ranking of projects as a present value analysis. Unless otherwise noted, the levelized costs or rates in this report are calculated in nominal dollars (i.e., inflation is included inside the levelization so no further adjustment is required for inflation) for a period of 30 years using Creative Energy's forecast WACC of 5.95%. A levelized *cost* is often used to compare different supply options. Levelized costs can take into account changes in production or consumption over the analysis period. A levelized *rate* is a way to compare different retail rate forecasts (e.g., for different fuels or thermal energy systems) without adjusting for any possible changes in consumption over time.

3. SITE SELECTION

One of the first tasks in this study was to identify a location for the Fuel Switch. The team reviewed a wide range of potential sites, focussing on industrial lands in the False Creek Flats and within the Port lands along the south shore of Burrard Inlet.

The False Creek Flats (also known simply as the Flats) is a key job centre in Vancouver. The Flats consists of approximately 182 hectares bound by Main Street to the west, Clark Drive to the east, Prior and Venables streets to the north, and Great Northern Way to the south. It is home to over 600 businesses and roughly 8,000 employees. The Flats is also home to seven universities and educational institutions, including the new main campus of Emily Carr University of Art and Design. The City's 1995 Industrial Lands Strategy identified the Flats as an essential area for industrial, transportation and service needs. The Preliminary Concept Plan for the Flats (developed between 1996 and 1999) established two industrial zones (I-2 and I-3) keeping traditional light industry in the eastern Flats while allowing for high-tech offices near transit and neighbouring communities. The 2005 Transportation and Rail Study reaffirmed the importance of rail lands and identified the need to grade-separate road vehicles from rail along the Burrard Inlet Line to the Port. The 2005 Metro Core Jobs and Economy Land Use Plan reconfirmed the Flats as a key area for jobs and economic activity (leading to rezoning policy for general office use in the I-3 zone). Last year the City initiated the Flats Area Planning Process to consider the future of the Flats.

The Port lands along the south shore of Burrard Inlet are home to two container terminals (Centerm and Vanterm), five bulk terminals and several industrial operations. The largest industrial operations are Rogers Sugar and West Coast Reduction, both of which also have significant process steam needs. Steam is currently generated at each site using natural gas. Rogers Sugar and West Coast Reduction are tenants of the Port. However, Rogers Sugar owns most of its property, with the exception of the shore loading area for the facility which is leased from the Port.

The search for a site was informed by previous screening studies and the project requirements, as well as discussions with real estate brokers, specific land owners, and the City. The key criteria used to identify possible sites for the Fuel Switch plant include the following:

Site Size: The minimum size threshold was set at ~10,000 m^2, whether in a single parcel or through possible amalgamation of parcels. This would provide sufficient space for up to a 90 MW thermal-only biomass plant with minimal on-site fuel storage. A smaller site may be possible with a reduced project scope or different configuration. For site screening, the team used 10,000 m^2 as the desired minimum threshold, but did not rule out slightly smaller sites if they looked promising with respect to other selection criteria.

Ability to Grow: Given the size of the project, distance to the existing system, high upfront development costs, and likely increase in demand for low-carbon energy in the future, the team also screened sites in terms of their ability to accommodate growth, either growth in thermal capacity or the addition of synergistic activities such as CHP. While this could be accommodated by selecting a larger initial site, an alternate and less risky approach would be to identify locations that could be expanded through the acquisition of neighbouring sites over time.

Fuel Delivery Options: The team also considered the suitability of sites for fuel delivery. This included both direct site access as well as overall proximity to trucking routes, rail, or barge delivery. Some preference was given to sites with multiple delivery options.

Orientation / Site Servicing: The team considered the suitability of the site shape for a biomass plant as well as proximity to utilities.

Cost of Land: The expected cost of land was also considered, whether in the form of an outright purchase of land or a lease rate. The team also considered the extent to which a purchase or lease can be phased for development and growth (through an initial option vs. immediate acquisition and the possibility of a phased acquisition).

Ownership / Availability: The team considered the existing ownership, use, value and likely availability of candidate sites. Sites owned by the City were of particular interest given the drivers for the project (community GHG emission reductions and other public benefits) and uncertainty over the actual cost or availability of land owned by third parties.

Distances: The team took into account distances to the existing Creative Energy steam plant on Beatty St, industrial loads at the Ports, and hot water networks (e.g., SEFC / NEFC).

Other Considerations: These included compatibility of the energy plant with surrounding land uses; possibility for other synergistic uses (e.g., food production); possibility to leverage other infrastructure projects to reduce project costs (e.g., the viaducts removal may reduce interconnection costs); environmental remediation requirements; seismic issues; etc.

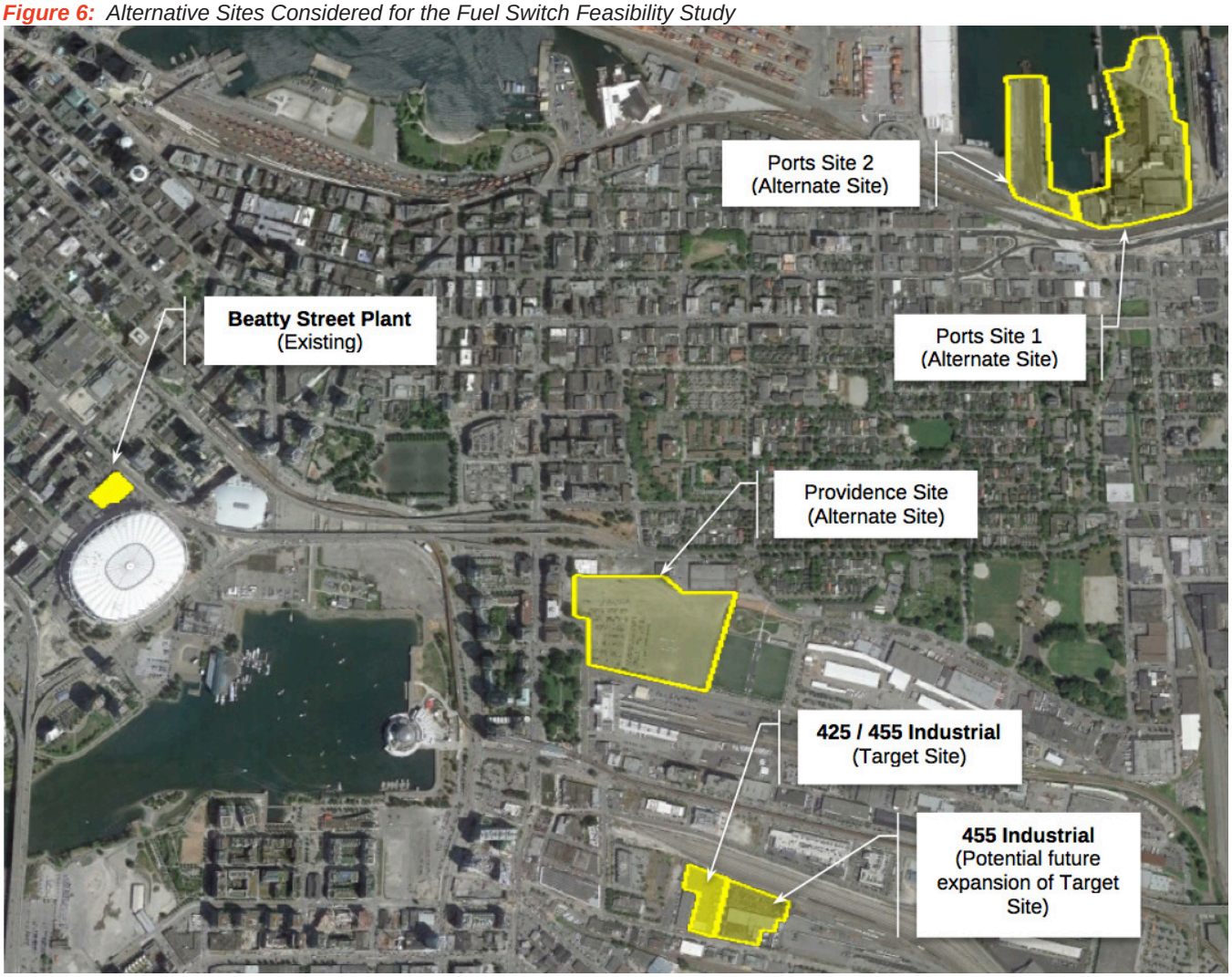
There are a limited number of potential sites that would likely be available and suitable for the Fuel Switch. Following a wide search within the Flats and Port lands, four sites were selected to carry into the initial interconnection study (Figure 6, Table 3). Two of the sites are located within the Port lands and two of the sites are on the False Creek Flats. The site at 425 Industrial was selected as the target site to carry into the remainder of the more detailed feasibility study.

The two sites considered in the Port lands are adjacent to one another. These were treated as a single location for the purposes of the interconnection study. Although these sites are within the Port lands, both are privately owned.[26] One site was recently acquired by the Washington Marine Group. At the time of the initial site selection and interconnection study, the future plan for this site was still unknown. The other site is owned by Rogers Sugar. This site contains a sugar refinery (served by an aging steam and CHP plant) and shipping facility. Both sites are farther from the existing Creative Energy steam plant at Beatty Street compared to the sites on the False Creek Flats. The increased distance would add $6 – $15 million to the interconnection costs alone, and there could also be additional complexity and risk associated with a more distant site. However, these Port sites would potentially allow both barge and rail delivery of fuel. The higher cost of interconnection may also be offset by the possibility of securing some large industrial steam loads within the Port lands (including Rogers Sugar). The Ports are also undergoing rapid electrification, which is apparently posing some challenges for the local electrical grid. A CHP plant at one of these sites could provide some further project value. Unlike large institutions such as UBC and SFU, the Port does not own or operate the electrical grid within its lands. The distribution grid within the Port lands is owned and operated by BC Hydro. The study team was unable to obtain any formal information on the current magnitude or cost of system constraints to meet ongoing electrification of the Ports. Further, at the moment there is no real mechanism to capture the benefits of grid support for a local CHP plant.

Ultimately, a location in the Port lands was excluded from the detailed feasibility study because of the additional distance to these sites; the uncertain future use and availability of these sites; the uncertain future of existing industrial steam loads within the Port lands; and the lack of

26 The waterfront lands between Canada Place and Portside Park were also considered by the study team. These lands are owned by Port Metro Vancouver. They are closer to the existing Creative Energy Steam plant (and potential Canada Place load), but they are designated as a special planning area. Port Metro Vancouver is still developing a long-term plan for these lands. Port Metro Vancouver also expressed some concern about the compatibility of an energy production plant with its primary mandate to use the Port lands to facilitate trade. For more information on the Port lands, see Port Metro Vancouver's comprehensive Land Use Plan released in October 2014 and intended to guide how Port Metro Vancouver develops its lands and waters over the next 15 to 20 years. The document can be found at: http://www.portmetrovancouver.com/wp-content/uploads/2015/06/port-metro-vancouver-land-use-plan-english.pdf.

Figure 6: Alternative Sites Considered for the Fuel Switch Feasibility Study



information on possible electric system benefits from a CHP plant as well as the lack of any mechanisms to capture such system benefits if they exist.

One of the sites identified on the False Creek Flats is an 7.3 hectare parcel currently owned by Providence Health Care. The Providence site (also referred to as the Station Street Site) is the proposed new location of St. Paul's Hospital. It is closer to the existing steam system than the target site, which would reduce interconnection costs for the Fuel Switch. There could also be additional project value created from co-locating a low-carbon steam plant within or adjacent to a new hospital campus. One of the primary benefits of co-location would be the avoided costs for on-site redundancy / back-up heating equipment, if required. In the case of a CHP plant, there could also be some avoided costs for back-up electrical equipment. In both cases, there would be added redundancy and resilience from the additional fuels (diesel, gas, and biomass). As a PSO, there would also be additional value to St. Paul's Hospital from avoided carbon offset requirements.

This site was not selected as the target site of the plant for the remainder of the feasibility study because of uncertainty over the long-term plan for the site. However, the site was used in the interconnection study to illustrate the potential benefits of reduced distance.

▲ *Street view of target site, 425 / 455 Industrial Avenue*

Since the completion of this feasibility study, Providence Health Care has initiated more detailed planning and Vancouver City Council has endorsed a policy planning program for the site. It now appears there may not be sufficient space within the current plans to accommodate the Fuel Switch plant, and there would be no space to allow for future expansion of the plant. Given the proximity of the Providence site to a proposed interconnection to the target site (below), it would still be possible for the hospital to acquire energy from the Fuel Switch project. This would reduce the hospital's ongoing requirements to purchase GHG offsets. Connection to the project could also be required under the City's green building and rezoning policies. The fact that the Providence site would be served from two directions and from two different plants with multiple fuel sources may also allow St. Paul's to avoid some or all of the space and costs for an on-site back-up heating plant. Alternatively, it may be possible to integrate any on-site back-up heating plant into the larger network to offset some of the costs and provide additional value from such a plant. These opportunities will continue to be explored by Providence, Creative Energy and the City.

The second site considered on the False Creek Flats is actually two adjacent parcels owned by the City at 425 and 455 Industrial Avenue. The parcel at 425 Industrial Avenue is the location of the City's impound lot, which is currently operated by Busters Towing. With a small boundary change between 425 and 455 Industrial Avenue, the parcel at 425 Industrial Avenue could accommodate the Fuel Switch plant. The adjacent site at 455 Industrial Avenue, which currently houses Recycling Alternatives, United We Can, and Busters' commercial towing operation and overflow space, provides some flexibility for a future expansion of the Fuel Switch plant. This expansion capability is an additional advantage to the target site at 425 Industrial Avenue.

Given uncertainty in the future availability and use of the other sites, the parcel at 425 Industrial

Avenue was ultimately selected as the target site for the purposes of the detailed feasibility study. This site is within City control. It is well suited for a plant in terms of its size, orientation and surrounding land uses. While more distant from the existing Beatty Street plant than the Providence site, it is still closer than the sites considered within the Port lands. It offers an opportunity for future expansion of the Fuel Switch (to the adjacent City-owned parcel at 455 Industrial Avenue). This site is also adjacent to the City's existing SEFC Neighbourhood Energy Utility, which may be able to use energy from the Fuel Switch. Finally, this location has the potential for both rail or truck delivery of fuel (the feasibility of rail delivery is discussed later in this report). As part of the conditional award of the City's downtown RFEOI to Creative Energy, City Council placed a hold on any changes in the current use of 425 Industrial Avenue site pending the results of this feasibility study and further negotiations. It is expected that the City would provide the land under a long-term lease. Although this site was used for the detailed feasibility study, Creative Energy will continue to monitor other potential sites.

Table 3: *Description of Alternative Sites*

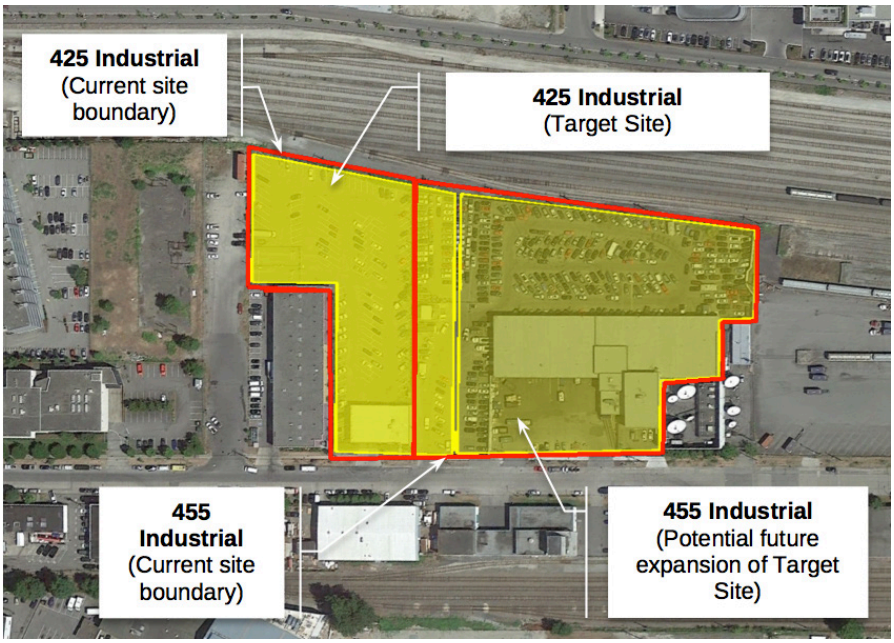
TARGET SITE (425 / 455 INDUSTRIAL AVENUE)	
	
Ownership:	Two adjacent parcels owned by the City. The west site (425 Industrial Avenue) was selected for the location. The east site (455 Industrial Avenue) is not required for proposed project size and does not form part of the detailed financial analysis but this parcel provides some opportunity to expand the plant in the future and was considered within the site concept renderings. A small boundary change is required between 425 and 455 Industrial Avenue to accommodate the plant but this boundary change would not affect any structures or significantly affect any existing uses of 455 Industrial Avenue
Available area (before boundary changes):	• 425 Industrial Ave.: ~0.7 ha • 455 Industrial Ave.: ~1.4 ha
Current uses:	• 425 Industrial Ave.: City impound lot (operated by Busters) • 455 Industrial Ave.: United We Can operations (social enterprise, bottle depot), Recycling Alternatives, and Busters' commercial towing / overflow lot
Approximate distance to existing Creative Energy steam plant:	2.4 km

Table 3 Cont'd: *Description of Alternative Sites*

PORTS SITES	
	
Ownership:	Two adjacent sites. West site is owned by Washington Marine Group and east site is owned by Rogers Sugar. Treated as a single location for the interconnection study.
Available area:	• West site: ~2.8 ha • East site ~6 ha
Current uses:	• West site: Rail spur • East site: Sugar refinery and shipping activities
Approximate distance to existing Creative Energy steam plant:	3.1 km
PROVIDENCE SITE (PROPOSED LOCATION OF NEW ST. PAUL'S HOSPITAL)	
	
Ownership:	Providence Health Care
Available area:	• Site is ~7.3 ha • Plans for new health care facilities to be confirmed
Current uses:	• Surface level parking
Approximate distance to existing Creative Energy steam plant:	1.1 km

4. INTERCONNECTION STUDY

In parallel with the initial site selection process, the team completed an interconnection study for each site in order to inform the final site selection and detailed feasibility study. The purpose of the study was to:

- identify a base routing,
- identify a base design specification for the interconnection piping system (pipe size, type, and condensate arrangement),
- identify possible interconnection optimizations, and
- develop a cost estimate to inform the detailed feasibility study.

As noted in the previous section, the two adjacent sites within the Port lands were treated as a single site for the purposes of the interconnection study. The scope of the interconnection study was from the property boundaries of each site to the existing Beatty Street plant. The assumption was that any piping costs within the selected site would be added to the final building and mechanical system costs for the site selected for the detailed feasibility analysis. In all cases the interconnection was assumed to tie into the existing Beatty Street plant at the main 14" steam header off boilers 1 and 2. A pressure reducing value and a steam vent to the roof would be required for the interconnection. These costs are included in the scope of the interconnection study. A schematic of the assumed tie-in arrangement at the Beatty Street plant is included in Appendix A.

4.1 ROUTING

All interconnection options were designed to terminate at the existing Creative Energy steam plant at 720 Beatty Street. The study team considered the possibility of an interconnection to some other point in the existing steam distribution network. However, this option was ruled out because of capacity limitations at other points on the network, and the operating advantages of having the new supply tie into the system at the existing steam plant, such as being able to monitor and control distribution pressures to the system, better control each plant dispatch, and centralize areas of the system requiring operator supervision.

The City provided input to support the selection of each interconnection route, including information on:

- existing utilities in city streets,
- planned new infrastructure projects and major infrastructure upgrades (installation synergies),
- high level information on soil conditions in the area, and
- anticipated development along the interconnection route (opportunities to connect new loads).

Figure 7 shows the base routing used in the interconnection study for the two adjacent sites in the Ports lands. Figure 8 shows the base routing used in the interconnection study for the sites in the False Creek Flats. The base interconnection routing from the Providence site is the same as the final segment of the interconnection routing from the site at 425 Industrial Avenue. Given uncertainty in the use and availability of the Port sites, more attention was paid to opportunities to optimize the interconnection route from the sites located on the False Creek Flats. Figure 9 summarizes the key interconnection optimizations considered in the detailed feasibility study. These are also discussed in more detail below.

Figure 7: *Base Interconnection Routing for Sites in the Port Lands*

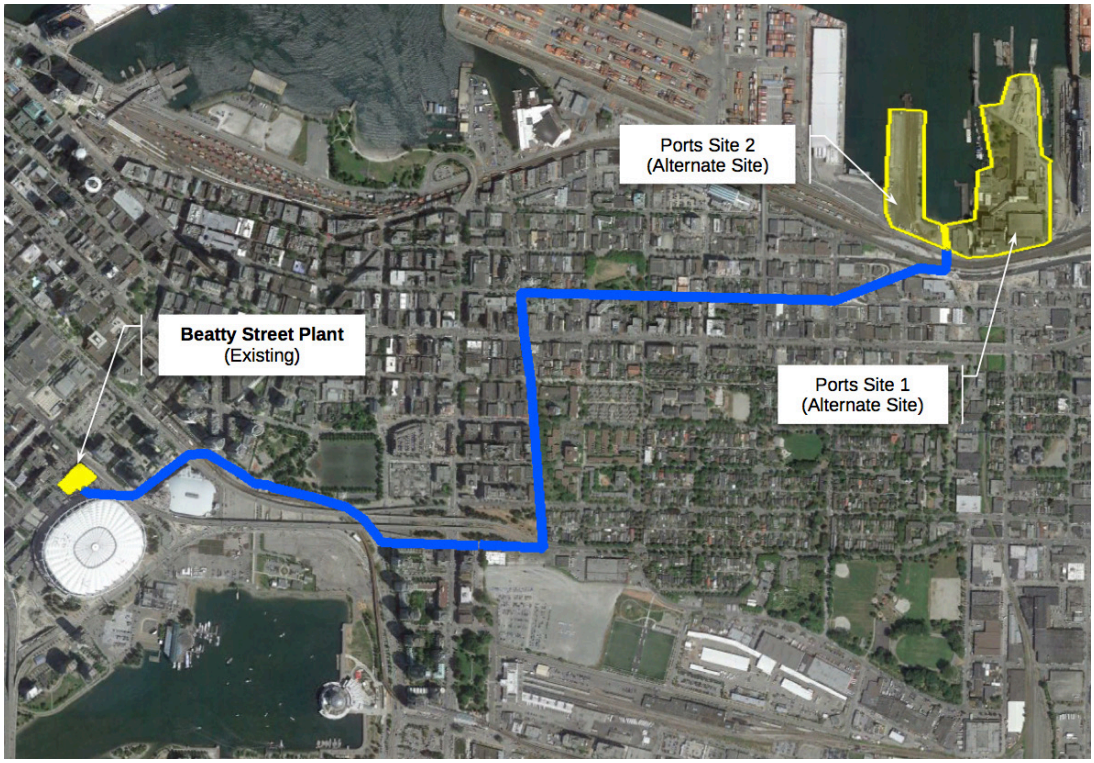


Figure 8: *Base Interconnection Routing for Sites in the False Creek Flats*

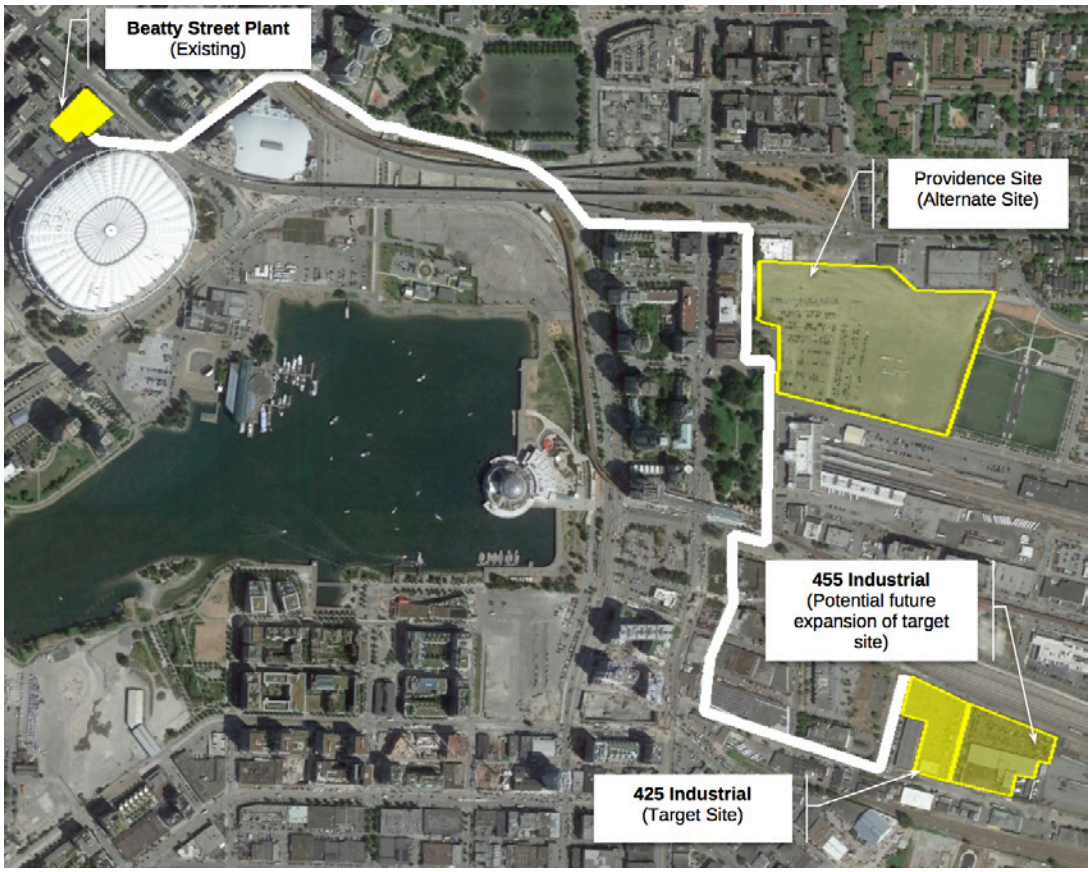
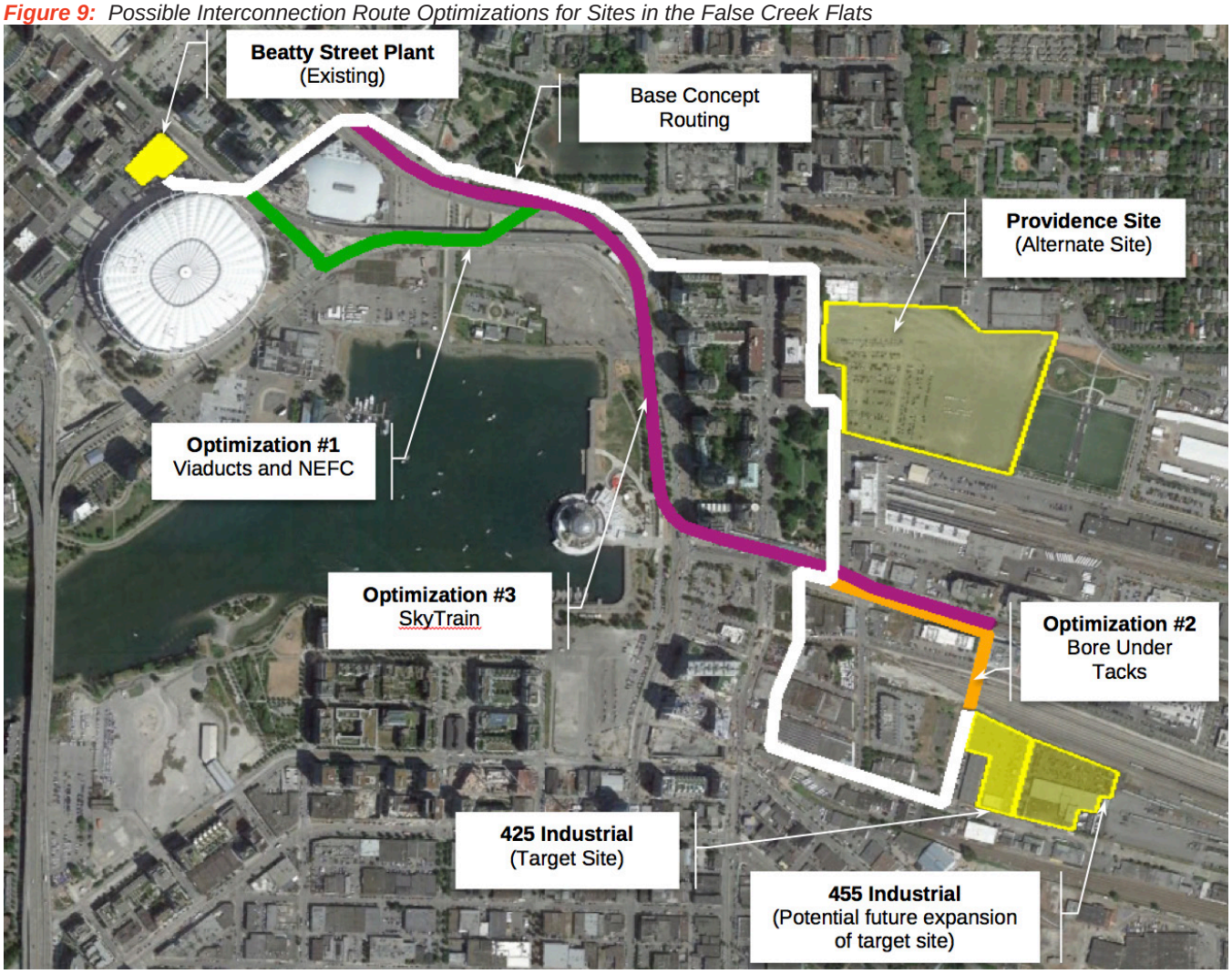


Figure 9: Possible Interconnection Route Optimizations for Sites in the False Creek Flats



4.1.1 Optimization 1: Viaducts and NEFC

The City is planning to remove the Georgia and Dunsmuir viaducts. This would include demolition of the viaducts and the creation of a new street network. This would also open up new residential and commercial development sites along with new public spaces. This optimization seeks to take advantage of the removal of the viaducts and development of a new local road network in order to lower the costs of the interconnection to the Fuel Switch. While this could lower installation costs, there is uncertainty in the relative timing of both projects. Further, given the proposed route within NEFC is on lands that previously hosted industrial activities, there is some higher risk the project could encounter contaminated soils, which would increase final costs. As of the completion of this feasibility study, the City has not yet completed a final plan or timeline for removal of the viaducts.

4.1.2 Optimization 2: Bore Under Tracks

Another potential strategy to reduce the interconnection costs from the site at 425 Industrial Avenue could be to bore under the railway tracks to shorten the length of this interconnection. This would likely require permission from the rail yard owner, Canadian National Railway Company (CN). Cost estimates for this optimization reflect the net effect of the shorter distance for the interconnection together with the added cost of horizontal boring below the railyard.

4.1.3 Optimization 3: SkyTrain

This optimization considers the possibility of hanging a significant portion of the interconnection under the elevated supports for Translink's SkyTrain (regional light rail). The key benefits from this optimization include:

- shortening the total interconnection pipe length by more than half,
- lowering the civil costs compared to buried pipe, and
- eliminating the need for costly steam manholes for a major portion of the route.

A preliminary concept for mounting the interconnection pipe was developed for initial proof of concept, and to support a cost estimate. Additional refinements to the design would be required prior to finalizing this approach. Additional information on this potential optimization is provided in Figure 10, Figure 11, and Table 4. Table 5 and Table 6 provide some examples of local and North American precedents for hanging steam pipes from structures. The City would likely need to play an active role in any discussions with Translink to secure this optimization.

Figure 10: *Sketch of SkyTrain Optimization*

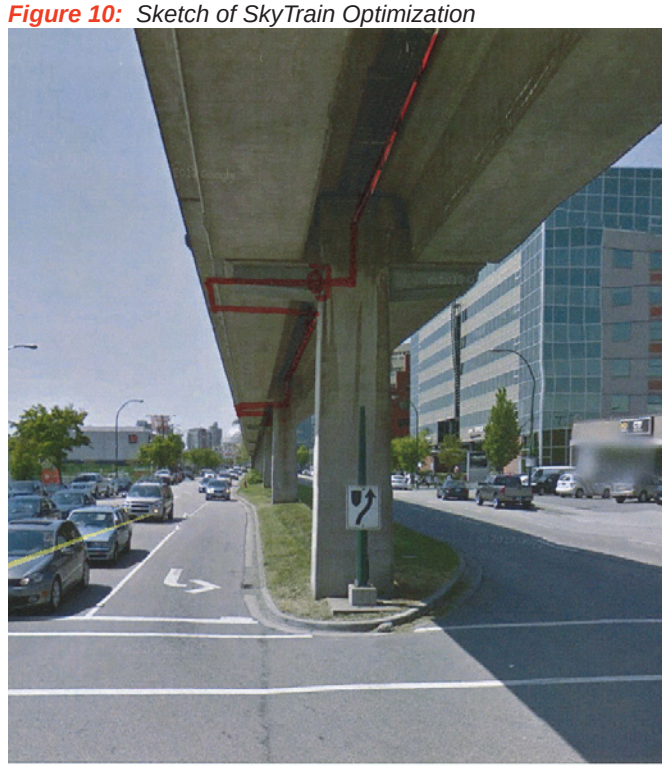


Figure 11: *Preliminary Mounting Details for Possible SkyTrain Optimization*

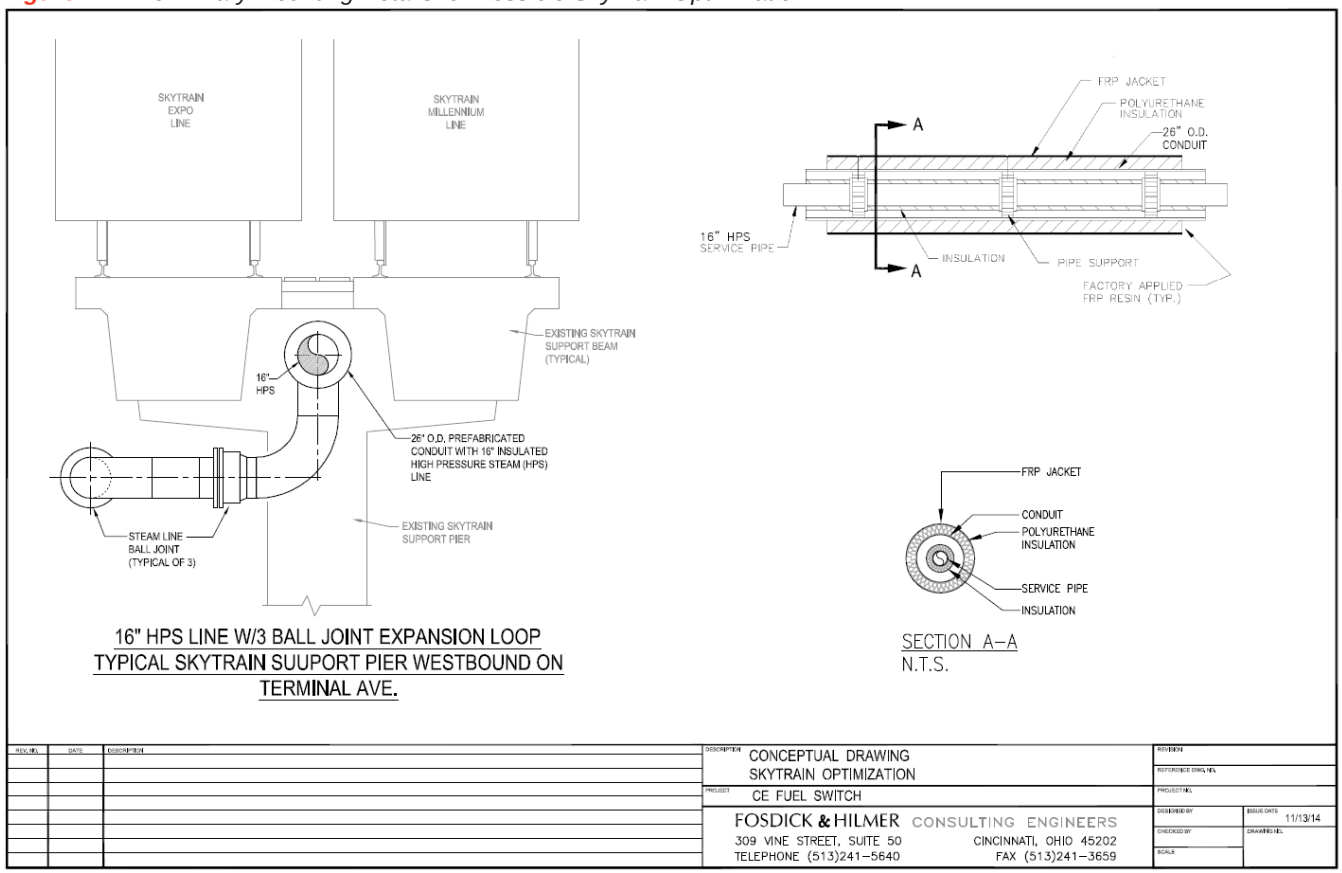


Table 4: *Information on Potential SkyTrain Optimization*

Physical Characteristics	The 406 mm (16”) steam line would be surrounded by insulation, an air gap, additional insulation and an outer jacket. The assembly would have a ~ 660-762 mm (26”-30”) outside diameter.
Risk Mitigation Measures	Pipe would be double walled and insulated to mitigate against steam leaks. The double wall design would allow for steam to vent to a controlled location if one were to occur. A full risk analysis and mitigation plan would be required in the next stage of design.
Accessibility	Accessibility will be required for operation and maintenance of any valves. These would most likely occur at branch connections. Steam trap stations including drip legs, steam traps and drain valves will require occasional maintenance access for trap repair/replacement and to operate drain valves (typically only during system start-up). Steam trap stations should be located at low points in the piping system and should be spaced at about every 60 to 90 m along the run. Some maintenance access to the pipe expansion devices may be required.
Expansion	In lieu of expansion joints, thermal expansion of the pipes would be accommodated by 3-ball joint expansion loops as shown in Figure 11. This also allows for routing around the SkyTrain support columns.
Mounting and Structural	As only limited structural details of the SkyTrain supports are publically available, a detailed mounting design was not developed. More detail will be required on the type of structural systems that are used for the SkyTrain supports including carrying capacity of existing supports, need for reinforcing column footings, and coordination of pipe routing and expansion devices to not interfere with existing equipment located on the SkyTrain supports.

Table 5: *Examples of Existing Creative Energy Steam Pipes Hung from Structures*

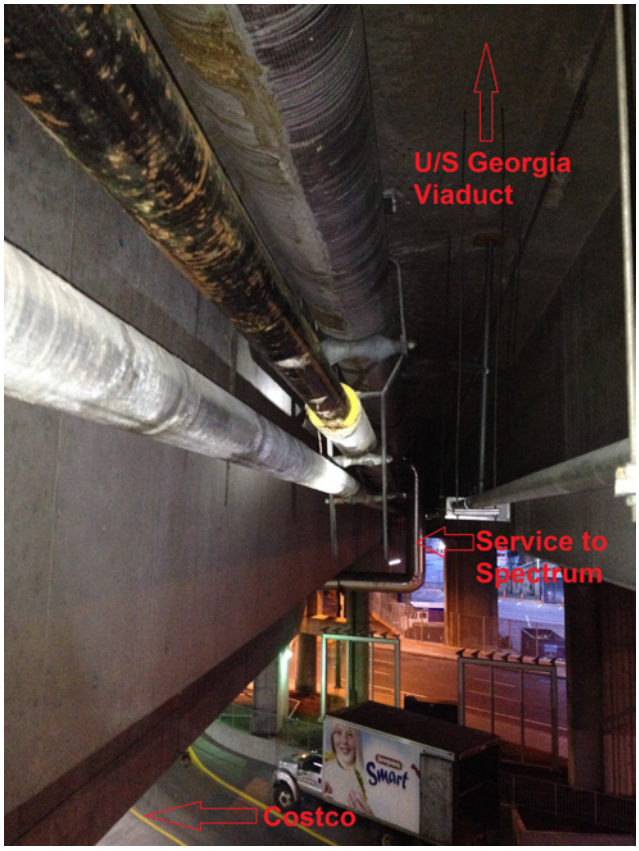
UNDERSIDE OF VIADUCTS 1	UNDERSIDE OF VIADUCTS 2
	

Table 5 Cont'd: *Examples of Existing Creative Energy Steam Pipes Hung from Structures*

UNDERSIDE OF VIADUCTS 3	UNDERSIDE OF FAIRMONT PAN PACIFIC
	

Table 6: *Some Other North American Examples of Steam Pipes Hung from Structures*

BOSTON, MA	
	An exposed 457 mm (18”) diameter steam pipe and 76 mm (3”) diameter condensate pipe hangs from the Lechmere Canal pedestrian overpass in downtown Boston, MA. The distribution pressure is 1380 kPa (200 psi) at 230ºC (450°F). Under the overpass the main line splits into parallel smaller diameter pipes in order to route under bridge space and preserve head room while hiding behind girders for optics.
INDIANAPOLIS, IN	
 	Two 500 mm (20”) dia. steam mains are suspended beneath a bridge near downtown Indianapolis, IN. One line operates at 1,720 kPa (250 psi), 340ºC (650°F) and was installed in the early 1970s. It is insulated with 100 mm (4”) of calcium silicate covered by an aluminum jacket. The other line operates at 2,760 kPa (400 psi), 370ºC (700ºF), was placed in-service in 1992, and is insulated with an aluminum jacketed, 150 mm (6”) thick foam glass insulation. Both lines remained in-service during a 2010-11 bridge renovation project, and they continue operating today. The face-to-face span between bridge abutments is roughly 200 m (650 ft).

4.2 INTERCONNECTION DESIGN

A number of design alternatives were considered in the interconnection study related to:

- pipe size,
- pipe type (i.e. pre-fabricated, or in-house fabrication),
- condensate arrangement, and
- manholes vs. trench-at-grade system.

The design alternatives together with the selected assumptions for the detailed costing are discussed below.

4.2.1 Pipe Size

The minimum size to interconnect a 65 MW baseload steam plant (the target size of the Fuel Switch) is a 305 mm (12") diameter pipe. Given the distance of the project and possible future expansion opportunities for the Fuel Switch, the costs and benefits of a larger 406 mm (16") diameter pipe were also considered. This larger diameter could accommodate up to 110 MW of transfer capacity within best practices for steam pipe design and operation (Table 7). Table 8 summarizes the difference in capital costs for each pipe size under the base routing to the site at 425 Industrial Avenue. Given the sunk nature of the interconnection, the possibility for future expansion of the Fuel Switch, and the relatively small incremental capital cost (~$2.4M or ~13%) for a much larger transfer capacity (110 MWt vs. 65 MWt), the 406 mm (16") diameter pipe was used as the basis for the interconnection cost estimates in the detailed feasibility study.

Table 8: Capital Cost of Alternate Pipe Sizes for Base Routing to 425 Industrial Ave.

PIPE SIZE	TOTAL COST [$000'S] ($2014)
305 mm (12")	17,200
406 mm (16")	19,600

4.2.2 Pipe Type

Two types of pipe were considered in the interconnection study: a pre-fabricated solution or an in-house fabricated solution. Currently, Creative Energy uses in-house fabrication for new distribution lines. However, there may be advantages with pre-fabricated pipe systems for the Fuel Switch interconnection as these typically include a leak detection system and may have superior insulation performance. Cost estimates were generated for both pipe systems (Table 9). A pre-insulated system was assumed for the base cost estimates in the detailed feasibility study given the small incremental cost and potential benefits.

Table 9: Capital Cost of Alternate Pipe Types for Base Routing to 425 Industrial Ave.

PIPE TYPE	TOTAL COST [$000'S] ($2014)
Pre-fabricated	19,600
In-house fabrication	19,200

Table 7: Interconnection Pipe Size, Operation and Capacity Assumptions

PIPE DIAMETER	PRESSURE DROP		VELOCITY		TRANSFER CAPACITY
	[m/kPa]	[psi/100ft]	[m/s]	[ft/min]	[MW]
305 mm (12")	38.9	1.72	50.8	10,000	65
406 mm (16")	11.3	0.5	30.5	6,000	65
406 mm (16")	33.9	1.5	50.8	10,000	110

4.2.3 Condensate Return

The interconnection to 425 Industrial Ave. was costed with and without a condensate return line (Table 10). A condensate return line would increase the cost of the interconnection about $3 million. Some of the benefits of condensate return include:

- possible fuel savings from increased plant efficiency,
- water savings, and
- possible savings in chemical treatment of water.

However, Creative Energy currently has minimal condensate return to the existing Beatty Street plant so very little condensate could be returned to the new Fuel Switch plant. At current levels of condensate return to the Beatty Street plant, even if all of this condensate was then returned to the Fuel Switch, it would produce present value savings in fuel, water and chemicals of at most $1 million, much less than the added capital cost of the condensate return line to the Fuel Switch. Further, any condensate returned to the Beatty Street plant during the peak heating season could be used within the Beatty Street plant, which would still be required for peaking. The potential for and value of condensate return to the Fuel Switch may increase in the long run as the existing steam system is converted to hot water. However, it may also be possible to add condensate return in the future. Given the preliminary screening of costs and benefits, condensate return is not included in the base concept for the Fuel Switch. However, the incremental costs and benefits of condensate return should be considered further in the detailed design phase.

Table 10: *Capital Cost of Condensate Return to 425 Industrial Ave.*

INTERCONNECTION FROM BEATTY STREET PLANT TO 425 INDUSTRIAL AVE.	TOTAL COST [$000'S] ($2014)
Without Condensate Return	19,600
With Condensate Return	22,700

4.2.4 Manholes

Steam manholes are required along the interconnection pipe routing to provide access to expansion joints and steam traps housed in the manholes. These devices require access for regular maintenance, and for eventual removal and replacement of equipment. Appendix A includes a drawing of the base interconnection routing to 425 Industrial Avenue. There are 26 manholes included in the base interconnection concept. Many of these could be avoided through the SkyTrain optimization.

Another possible optimization to limit the number of manholes is a trench-at-grade pipe system. This would eliminate the cost of manholes, as the expansion devices would be accessible from removable access panels at grade. This optimization was identified during the latter part of the interconnnecion study and it was not confirmed that this type of installation would be appropriate for all points on the base concept routing. As such it was decided to maintain the direct bury system as the base concept, and treat trench-at-grade as an optimization.

Elimination of the manholes results in a substantial cost savings, although the savings from this arrangement would be lower in scenarios that have fewer manholes (e.g., SkyTrain optimization). A trench-at-grade design would increase the pipe cost by ~ 50% to accommodate for the trench walls and pipe mounts. However, some further savings may be possible in civil costs with a shallower depth of bury. Savings in these costs are difficult to estimate without a more detailed design and have therefore not been considered in this initial costing exercise. Figure 12 shows photos and a typical detail of a trench-at-grade design. Table 11 summarizes the costs for a direct bury arrangement with manholes vs. a trench-at-grade arrangement.

Figure 12: Photos and Typical Detail of Trench-at-Grade Design

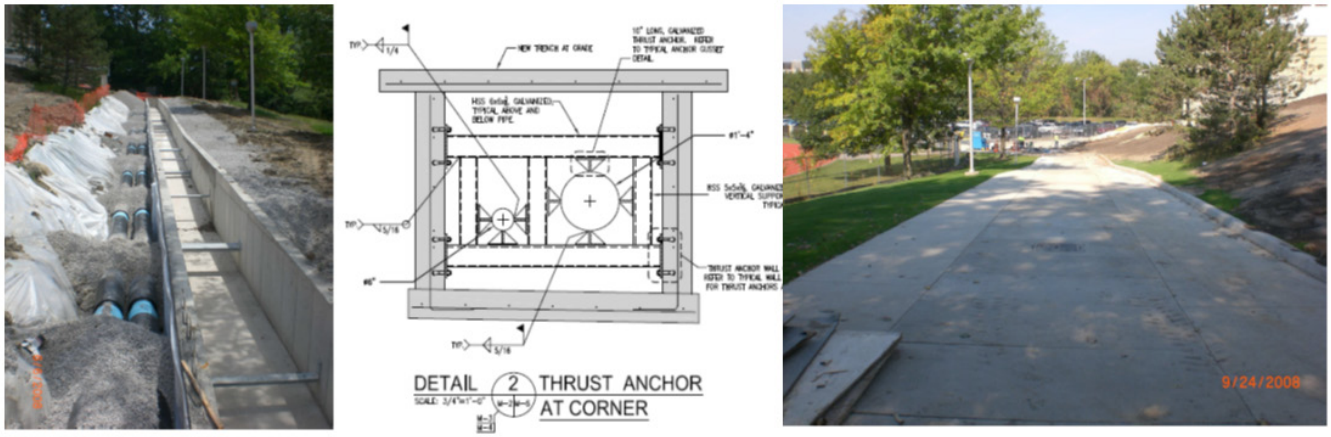
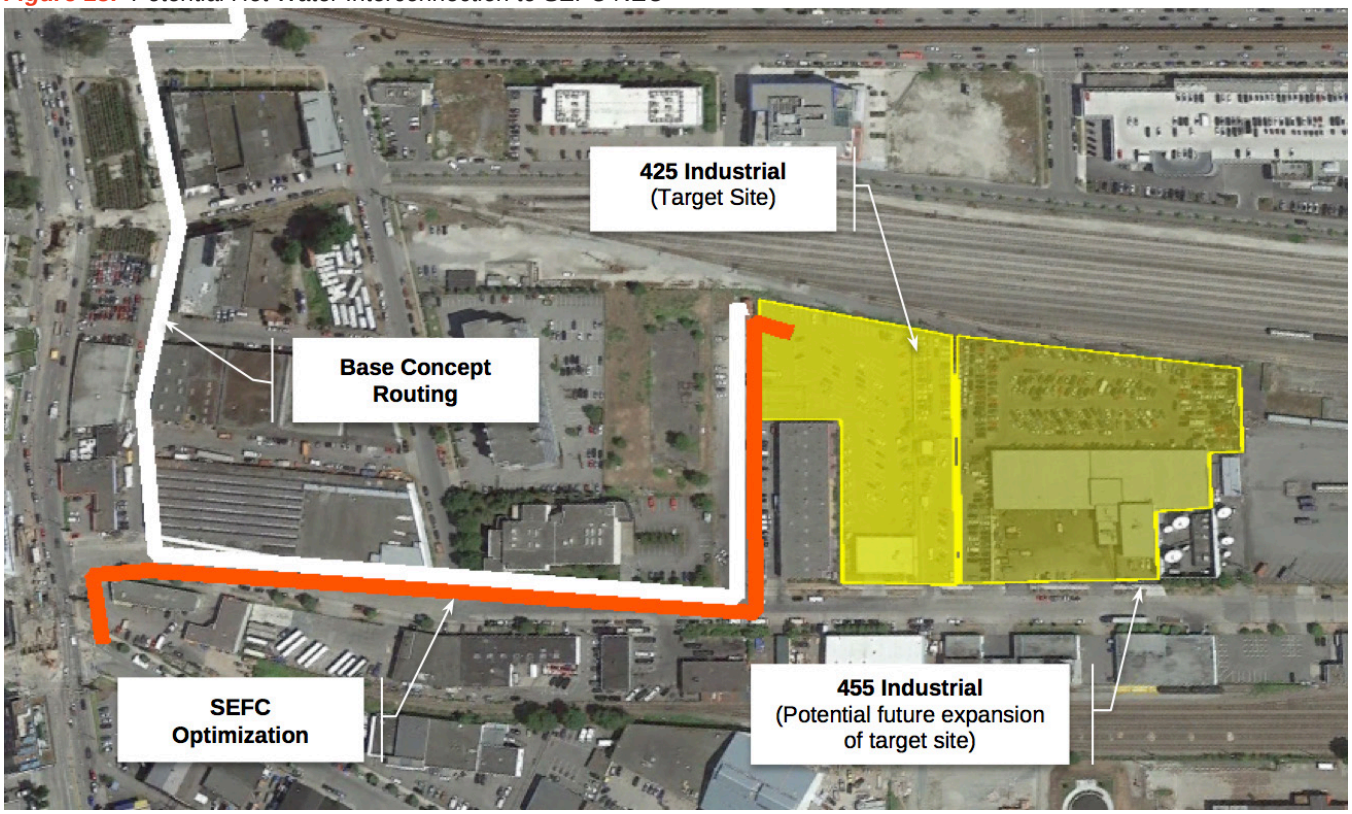


Table 11: Capital Cost of Direct Bury with Manhole vs. Trench-at-Grade Arrangement

PIPE SYSTEM (Base Interconnection Route to 425 Industrial Ave.)	TOTAL COST [$000'S] ($2014)
Direct buried with manholes (used for feasibility study)	19,600
Trench-at-grade	14,400

Figure 13: Potential Hot Water Interconnection to SEFC NEU



4.3 INTERCONNECTION TO SEFC

The target site at 425 Industrial Avenue is adjacent to the City's SEFC NEU. SEFC will require additional low-carbon energy with ongoing growth. One option is for the City to expand the existing sewer heat recovery system at its plant next to the Cambie Street Bridge. However, the City could also acquire additional energy from the Fuel Switch if this option is cheaper. This would provide additional load security for the project. The SEFC NEU uses a hot water network, which may also open up opportunities for additional heat recovery from the plant. As part of the interconnection study, a cost estimate was developed for a hot water interconnection from 425 Industrial Avenue to a nearby tie-in to the SEFC NEU distribution network (Figure 13). A pipe size of 200 mm (8") was assumed for the interconnection. A 200 mm (8") line could accommodate 15 MW of heat supply to the SEFC system. Costing for this interconnection was based on the cost of other recent system extensions for SEFC.

4.4 INTERCONNECTION COSTING SUMMARY

Table 12 summarizes the key assumptions and cost estimates for the base interconnection routing to each of the sites considered for the interconnection study as well as the impact of various potential optimizations for the interconnection to the target site at 425 Industrial Avenue.

Unit costs ($/trench m) were used to estimate mechanical and civil costs for pipe. An additional premium was then assigned to these unit costs for any complex intersections or streets where relocation or removal of existing utilities may be required. A typical manhole cost was established based on recent projects by Creative Energy. Soft costs (construction management, construction change allowance, and engineering) were established as a percentage of the pipe and manhole costs.

Table 12: *Summary of Interconnection Costs ($2014)*

SCENARIO	INTERCONNECTION LENGTH	MANHOLES	PIPE COSTS	MANHOLE COSTS	SOFT COSTS	TOTAL COSTS
	[m]	[#]	[$000s]	[$000s]	[$000s]	[$000s]
Base Routing to 425 Industrial Avenue	2,370	26	7,400	7,700	4,300	**19,600**
Base Routing to Providence Site	1,050	12	3,600	3,400	2,200	**10,200**
Base Routing to Port Site(s)	3,080	36	8,900	10,600	5,600	**25,300**
Optimization #1 to 425 Industrial Routing (Coordination with Viaducts Removal Project)	2,390	26	7,000	7,700	4,200	**19,200**
Optimization #2 to 425 Industrial Routing (Bore Under Tracks)	2,000	22	7,200	6,500	3,900	**18,200**
Optimization #3 to 425 Industrial Routing (Use of SkyTrain)	2,240	12	6,100	3,600	2,800	**12,700**
Optimizations #2 & #3 Combined	1,880	6	5,700	1,700	2,100	**9,600**
Additional Cost of SEFC Interconnection	560	N/A	1,110	N/A	320	**1,420**

The detailed feasibility study that follows is based on the site at 425 Industrial Avenue and the interconnection costs carried in the base financial analysis is $19.6 M ($2014). The basis for this cost estimate is as follows:

- Routing that follows the base concept routing in Figure 8,
- 406 mm (16“) steam line that can accommodate a target baseload of 65 MW but has the potential to transmit up to 110 MW if required in the future,
- Pre-insulated steam pipe with leak detection and advanced insulation properties to minimize heat losses,
- No condensate return line (based on preliminary costs and benefits of condensate return but to be considered further in detailed design phase), and
- A direct-bury pipe system with 26 manholes for valves, steam traps and expansion devices at changes in pipe direction.

These are considered conservative and prudent assumptions for the base case. Potential optimizations to this base configuration are less certain and these are therefore considered in sensitivity analyses. Table 13 summarizes the impact of these optimizations for the interconnection costs and also preliminary recommendations with respect to each interconnection optimization.

Table 13: *Summary of Interconnection Optimizations for 425 Industrial Ave. Site*

OPTIMIZATION	CAPITAL COST SAVINGS RELATIVE TO BASE CASE	RECOMMENDATIONS
Bore Under Tracks Only	7%	The use of the SkyTrain alignment and boring under the tracks are both technically feasible and would produce significant cost savings, particularly if pursued together. However, these optimizations will also require coordination with external parties (TransLink and CN) and they would likely also require support from the City. These are the most important optimizations for Creative Energy and the City to continue to pursue.
Use of SkyTrain Only	35%	
Use of SkyTrain + Bore Under Tracks	50%	
Trench-at-Grade	25%	This optimization is particularly important if the SkyTrain optimization is not possible. Even if the SkyTrain optimization is possible, there may still be opportunities to use this approach for the remainder of the interconnection route.
Coordination with Viaducts Removal	2%	This optimization has fewer savings and would introduce some additional complexity and risks in terms of coordination of schedules and possible disturbance of contaminated soils. This optimization is lower priority but the City and Creative Energy should continue to consider possible synergies between these two projects.

5. PLANT TECHNOLOGY SELECTION

5.1 GENERIC PLANT CONCEPTS AND COMPONENTS

There are a limited number of technologies to produce low-carbon steam. Previous screening studies narrowed the technically and economically feasible options to biomass, and in particular clean urban wood waste. There are thousands of global precedents for energy production from clean urban wood waste. Locally, the University of British Columbia and downtown Seattle both have operating systems that use clean urban wood waste. Other examples are provided in Table 1 above.

The composition and availability of clean urban wood waste is discussed further in Section 6. This section describes the production technology, together with the cost and performance assumptions used in the feasibility study. The plant would consist of three main components:

i. fuel delivery, storage and handling equipment,

ii. heat generation equipment (boilers and ancillary equipment), and

iii. emissions controls (including stacks and ash disposal systems).

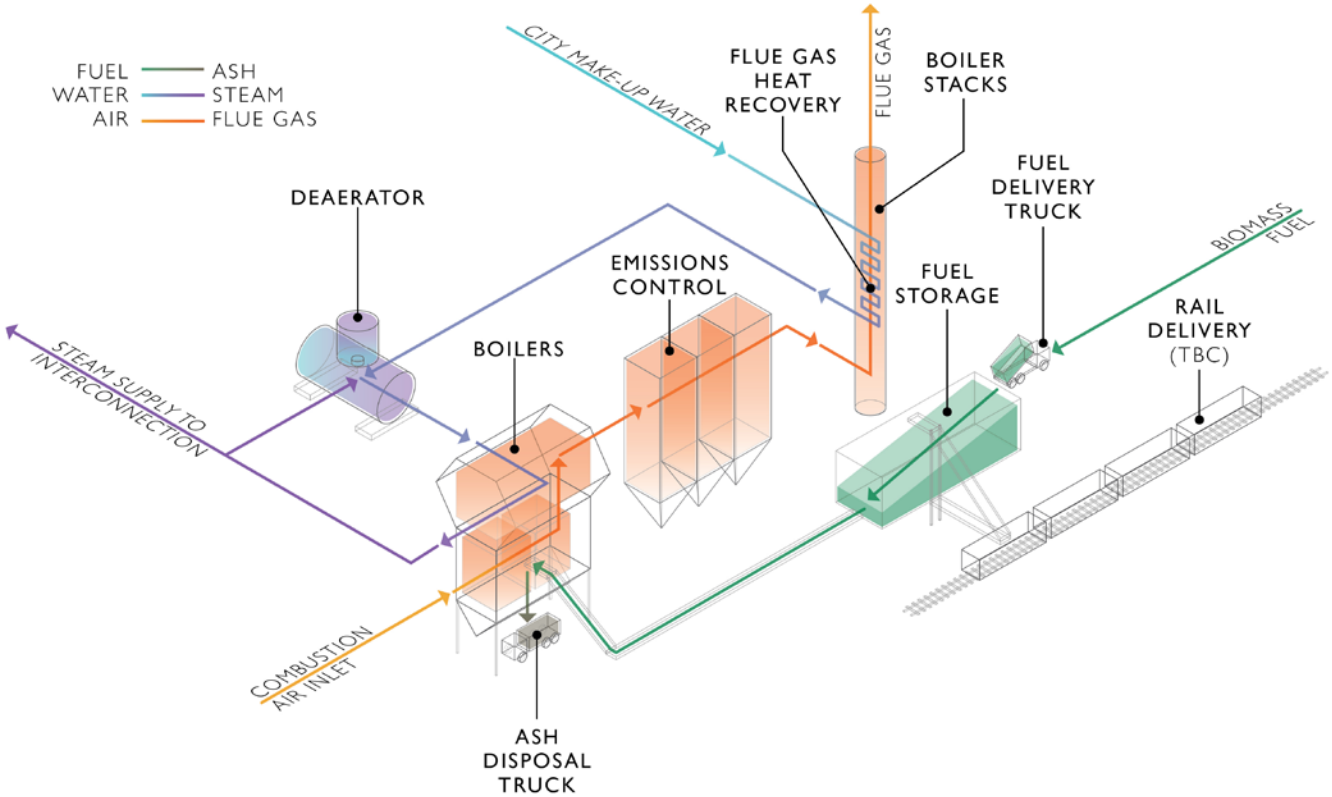
Other optional elements could include flue gas heat recovery and the addition of electricity generation. A basic plant concept is shown in Figure 14. However, there are many possible variations in the types of individual systems and the overall integration of system components.

This study only considers technologies that can use clean urban wood waste. Much broader waste-to-energy (WTE) technologies are not considered. The key difference between WTE and biomass plants is the type of fuel the plant can accept. WTE plants are designed to accept many different sources of waste including plastics and metals. Biomass plants are designed to accept only solid wood waste, and in this case untreated urban wood waste. While both WTE and biomass plants may use similar types of emissions controls (e.g. baghouses, electro-static precipitators, multi-cyclones, etc), larger and multiple types of emission controls are typically required in WTE plants. WTE plants also typically have much larger minimum efficient scales and much taller stacks.

Fuel delivery, storage and handling are important considerations in the design of an energy plant using solid fuel. Poorly designed or executed fuel delivery, storage and handling systems can have a major impact on plant availability and operating costs. For this project, the general concept assumes fuel will be stored in below-grade pits. These fuel pits will be integrated into the foundation. They will have concrete walls and hydraulic rams to move the fuel to a conveyor belt and/or augers, which in turn will move the fuel to the heat generation equipment. Conveyor belts may help minimize the possibility of fuel jams. Screens and magnets would be used in the system to remove potentially damaging and unwanted material (e.g., nails or rocks) before the fuel reaches the heat generation equipment.

Emission controls will normally consist of multiple systems. In biomass plants the main focus tends to be on control of particulate matter (PM), but active nitrogen oxides (NO_x)control is also possible if necessary. PM control systems typically consist of a multi-cyclone for the separation of dust and gases with an electrostatic precipitator (ESP) or baghouse filters as a secondary control. European plants tend to use a baghouse, while North American plants generally tend to include an ESP. Data from vendors and operating plants suggests both approaches can meet target emission performance. Large systems will typically also include continuous emissions monitoring systems.

Figure 14: *Generic Plant Concept Diagram*



5.2 TECHNOLOGY REQUEST FOR INFORMATION (RFI)

In order to validate the capital cost, space requirements, and performance assumptions for the Fuel Switch, the feasibility study included an international Request for Information (RFI) from technology vendors. The RFI process was also used to create a potential shortlist of vendors for a second round of procurement should the project advance to implementation. The RFI included a preliminary design basis that was developed for the feasibility study in consultation with the technical advisor to the study (Table 14). All respondents were asked to provide a response that would meet the same preliminary design basis and included all of the elements in Table 15. There are many separate equipment vendors that could provide individual system elements. However, based on site visits and experience from other plant operators, the study team elected to seek responses only from firms or consortia that could provide an integrated solution encompassing the full scope and technical specification for the mechanical plant. This was considered particularly important for achieving the best emission outcomes. Real-world experience has shown that a high degree of integration is required between production systems and emission control systems during the design, sourcing, installation, and operating phases to achieve the lowest emissions. Respondents were requested to provide preliminary equipment layouts based on the site conditions in order to confirm site viability and support development of building concepts and costs. Respondents were also encouraged to provide additional information on optional modifications or refinements such as larger sizes, addition of CHP, addition of flue gas heat recovery, and additional emission controls (Table 16).

Table 14: *Preliminary Design Basis for Technology RFI*

DESCRIPTION	DETAILS
Steam Output	• 65 MWt ±10% at the plant gate (i.e., net of any internal (parasitic) losses) • Expected boiler pressure at 2,000 kPa • Expected interconnection delivery pressure at 1,500 kPa
Condensate Return	No condensate return. Make-up water available at 10°C average temperature from municipal water supply.
Hot Water Host	6 MWt ±10% of hot water energy supply to nearby hot water host (for this RFI, assume temperatures are static over the course of the year) Supply 65 °C Return 50 °C
Fuel Specification	A base fuel specification for the purposes of the RFI responses is as follows: • Solid woody biomass (primarily clean urban woodwaste) • Average 30% moisture content (for efficiency calculation) • Proponents to provide the range of moisture content they can accommodate and the expected efficiency at alternate moisture contents • < 75 mm minus, average 25 mm minus, <10% pass 3 mm mesh • < 5% ash/non-combustible content by weight
Fuel Storage Requirements	Base storage requirement of 3 days at peak (final storage requirement pending)
Emissions	The project will require a special permit from Metro Vancouver, the local regulator of air quality. For the purposes of RFI responses, systems should be designed to meet or exceed the emission control requirements set out in Metro Vancouver Bylaw 1190.
Site Conditions	For the purposes of this RFI, responses should assume a rectangular site (aspect ratio approximately 3:2), with rail access along the long edge of the site. Truck access to the site is possible on the two shorter edges of the site and should be incorporated in a drive though fashion (i.e. entering the site at one end and exiting the other). One of the potential sites is near water. Additional information on fuel handling systems for receiving fuel by barge is encouraged. All sites are located in dense urban settings. Provisions for noise abatement, dust control, etc. will be integral to the final design. For the purposes of this RFI, equipment selection should be done with noise considerations in mind, and with the expectation that noise abatement will be an integral part of the equipment and building design solution.

Table 15: Base Project Scope and Information Requirements for Technology RFI

DESCRIPTION	DETAILS
Fuel Delivery	Equipment necessary to receive the fuel from a railroad freight car (preferred delivery option, subject to further due diligence) and large truck (53 ft. long, back-up). The energy centre will need to be able to accept fuel from both delivery means. Creative solutions for accepting fuel from multi-delivery modes are encouraged. Responses should be optimized for lowest cost and lowest footprint.
Fuel Storage	Equipment and infrastructure necessary to store fuel for conveyance to steam generation equipment. Storage must include fire suppression and ventilation equipment to satisfy applicable codes and standards in British Columbia.
Fuel Handling	Equipment necessary to convey fuel from the storage area to heat generation equipment. Responses should be optimized for durability and to minimize downtime of fuel handling system.
Heat Generation	Equipment necessary to generate heat per the preliminary design basis. System should be optimized for cost, and overall system efficiency.
Heat Distribution	Equipment necessary to distribute steam and hot water generated within the energy centre to an exit point at the energy centre.
Ash Collection and Disposal	Responses must make provisions for ash collection. Provide estimated volumes of ash based on design basis fuel.
Emissions Controls	Proponents should demonstrate that they are capable of meeting or exceeding the emission control requirements set out in Metro Vancouver Bylaw 1190 under the base fuel spec.. Proponents are encouraged to provide additional information on how they will meet or exceed these requirements, and also to provide data on actual achieved emissions from existing plants.
Foundations	Respondents should provide the cost for equipment foundations.
Building	Respondents are encouraged to provide cost estimates for the overall building and building foundation, however, this is not mandatory.
Layout	Responses should provide a concept/schematic level energy centre layout drawing for the base scope described above.

Table 16: Optional Information Requests

DESCRIPTION	DETAILS
Upsize Capacity	A larger capacity energy centre to the base requirement may be considered. Responses should provide a high level cost estimate and space requirements for one or more increments in capacity over the base specification (up to a maximum of 90 MWt steam generation and 10 MWt hot water generation.
Combined Heat and Power (CHP)	Combined heat and power may be considered. Respondents are encouraged to describe their approach to CHP (e.g ORC, back pressure turbine, etc.). Responses should include additional fuel requirements, high level cost estimates and performance assumptions including heat to power ratio, maintenance considerations, and any other relevant information.
Additional Flue Gas Heat Recovery	Heat recovery from the flue gas may be considered. Strategies may include heat recovery for: • Hot water heat host (see design basis for hot water heat host details) • Fuel drying • Combustion air pre-heating • Boiler feedwater pre-heating Responses should comment on heat recovery dispatch strategy, and include all equipment necessary for the heat recovery strategies identified. Responses should provide high level incremental cost estimates and performance characteristics of heat recovery system.
Enhanced Emissions Controls	Enhanced emissions controls may be considered. Responses should provide the cost for any enhanced emissions control strategies and how they influence performance. Strategies may include reduced PM_{10} and $PM_{2.5}$, and additional NO_x abatement. Provide incremental cost, and changes to emissions performance limit for the given base fuel spec..
Fuel Flexibility	Within the range of woody biomass, indicate the range of moisture content (max and min) and chip size (max and min) that the system can accommodate. Comment on how this influences efficiency at the high and low ranges of moisture content.
Availability	Comment on availability, major maintenance schedules or key equipment maintenance schedules. Provide an estimate of the weeks or days of annual downtime for each unit for regular scheduled maintenance.
Other	Respondents are encouraged to suggest other information that may provide benefit to the project that was not listed within this RFI.

Sixteen respondents from Canada, the U.S., Germany, Austria, Denmark, and France registered for the technology RFI process. Ten responses were received that satisfied the minimum project scope and preliminary design basis. Four responses were selected for an initial shortlist, although Creative Energy has reserved the right to alter the short list to include other vendors based on further changes in project scope or new information. The initial shortlist was used to establish assumptions for technology costs and performance in the detailed feasibility study. The initial shortlist was established taking into account:

- Vendor experience and references;
- Overall value, taking into consideration not only technology capital costs but space requirements, fuel efficiency, emission performance, and ongoing operations and maintenance requirements;
- Ability of the vendor to provide local service (training, maintenance support, replacement parts, etc.), both pre- and post-commissioning; and
- System flexibility including fuel flexibility, ability to turn down plant capacity, and expandability of system (including possible addition of CHP).

RFI responses included a range of heat generation approaches including bubbling fluidized bed, grate furnace, and gasification systems. Only two responses proposed gasification systems. Given the target scale of this project, the land constraints, and the exclusion of

Table 17: Comparison of Two Classes of Shortlisted Biomass Technologies

	BUBBLING FLUIDIZED BED	GRATE FURNACES
Module Sizes	Single 65 MW module	3 @ 22 MW
Turn Down Ratio (Module / System)	~ 2 : 1 (module) ~ 2 : 1 (system)	~ 3 : 1 (module) ~ 10 : 1 (system)
Efficiency (Before Flue Gas Heat Recovery)	75-80%	75-85%
Incremental Capacity Costs	Lower, however, fixed at outset	Higher, but greater flexibility to add another module in the future
Enhanced Emissions Controls	Additional NO_x abatement possible	Additional NO_x abatement possible
Fuel Flexibility	Appears to accommodate a wide fuel spec., and is better at accommodating changes to fuel spec. in the future	Furnace design tied to fuel spec.. Able to handle a wide fuel spec., if it is considered at the design stage.
Annual Availability	95%	90%

CHP within the base concept for the project, none of the gasification proposals were selected for the initial shortlist or feasibility study assumptions. The initial shortlist includes systems based on both grate furnaces (rotary and step grates) and bubbling fluidized bed boilers. Table 17 compares representative information on each class of technology.

5.3 BASE TECHNOLOGY ASSUMPTIONS FOR FEASIBILITY STUDY

The RFI responses allowed the team to refine the base concept for the project. Many elements of the preliminary design basis (Table 14) were maintained for the purposes of the detailed feasibility study (e.g. target plant capacity, condensate arrangement). However, a few parameters were adjusted in preparing estimates of capital costs and performance for the financial model. These include the following:

- Based on further research into the practical viability of rail delivery (see Section 6.4), the primary fuel delivery method assumed in the base system concept is truck. The site concept (layout) can still accommodate rail delivery should this prove viable in the future. Given the lack of condensate return in the base specification, the capital costs and system performance include an allowance for heat recovery from the flue gases to pre-heat the boiler feedwater. This energy recovery opportunity will result in a 5-10% increase in the heat output capacity of the plant. This is considered the most optimal use of flue gas heat recovery assuming 100% make-up water at around 10°C. This would allow a significant amount of energy to be recovered from the flue gases. However, flue gas heat recovery could be used to meet other internal loads or external hot water demand. These other options will be considered further in the final design stage. In the meantime, the use of flue gas heat recovery to pre-heat boiler feedwater provides a reasonable representation of the costs and benefits of flue gas heat recovery in the project for the purposes of this feasibility study.

- While a continuous emissions monitoring system (CEMS) was not included in the base specification for the RFI for simplicity, it is included as part of the base concept for the project. The criteria for emissions control in

the RFI was for compliance with the Metro Vancouver bylaw which does not specify a CEMS requirement. Given the cost and scale of the project, and the cost for CEMS, it is appropriate to include CEMS in the base concept for the Fuel Switch project.

Among the short-listed responses there were minor variations in cost, space requirements and performance. Using the shortlisted responses, a representative set of assumptions was developed for space requirements, capital cost, and system performance to guide the more detailed site concept and financial analysis in the feasibility study. These assumptions are summarized in Table 18. Appendix A includes the representative plant schematic for these assumptions.

The capital costs in Table 18 include equipment, installation and soft costs (design and engineering) for the base scope. Contingency, PST and interest during construction (IDC) are added separately within the financial model. The technology cost estimates only include mechanical costs. Building costs are discussed in Section 7.

The final selection of technology and vendor will be made through a competitive tendering process following confirmation of a final project scope, enabling agreements and the receipt of a CPCN from the Commission. It is expected the final tendering process will include cost, performance guarantees and emission guarantees.

The final system performance will also depend on the final fuel specification. The financial model is based on the efficiency assumptions in Table 18, which reflects the base fuel specification assumptions for the technology RFI. Additional sensitivity analysis is conducted on alternative fuel specifications and plant efficiency in the financial analysis.

Table 18: *Base Technology Assumptions Derived from RFI Results*

COMPONENT	TECHNOLOGY CAPITAL COST* [$000's] ($2014)	AREA REQUIRED [m²]	PERFORMANCE ASSUMPTIONS
Fuel Delivery, Storage, and Handling	50,375	2,150	36 hours of storage
Heat Generation		2,750	80.8% fuel to heat efficiency (using base fuel specification)
Emission Controls		1,750	Emissions guaranteed to be lower than requirements in Metro Vancouver Bylaw 1190

** The integration among each component did not allow for easy separation of individual system component costs, and this separation was not required for the financial analysis in the feasibility study.*

6. CLEAN URBAN WOOD WASTE

6.1 INTRODUCTION

Clean urban wood waste is a low cost, local fuel suitable for generating steam. It is also considered carbon neutral under all current GHG accounting standards (more below). There are three main sources of clean urban wood waste targeted for this project: park and yard trimmings; clean construction, demolition, and land clearing waste; and clean industrial and commercial wood waste. Contaminated wood, virgin forests, and so-called energy crops are controversial fuels in terms of GHG neutrality and emission management, and these are not considered for this project (see Figure 15). Park and yard trimmings represent an important but small (<10%) portion of potential fuel for the project. Most of these wastes are controlled by municipalities such as the City of Vancouver. The most desirable fuels for energy production are larger trunks, branches (without leaves, minimal bark), and wood waste from parks operations (fences, pallets). These are also not suitable feedstock for composting. The most significant source of fuel would be waste wood from construction. Demolition and land clearing. Supplemental commercial and industrial sources of wood waste include waste from local mills (wood chips, shavings, and other residuals from processing raw logs), cabinet and furniture makers, and used shipping pallets.

Figure 15: *Target Sources of Biomass for Fuel Switch*

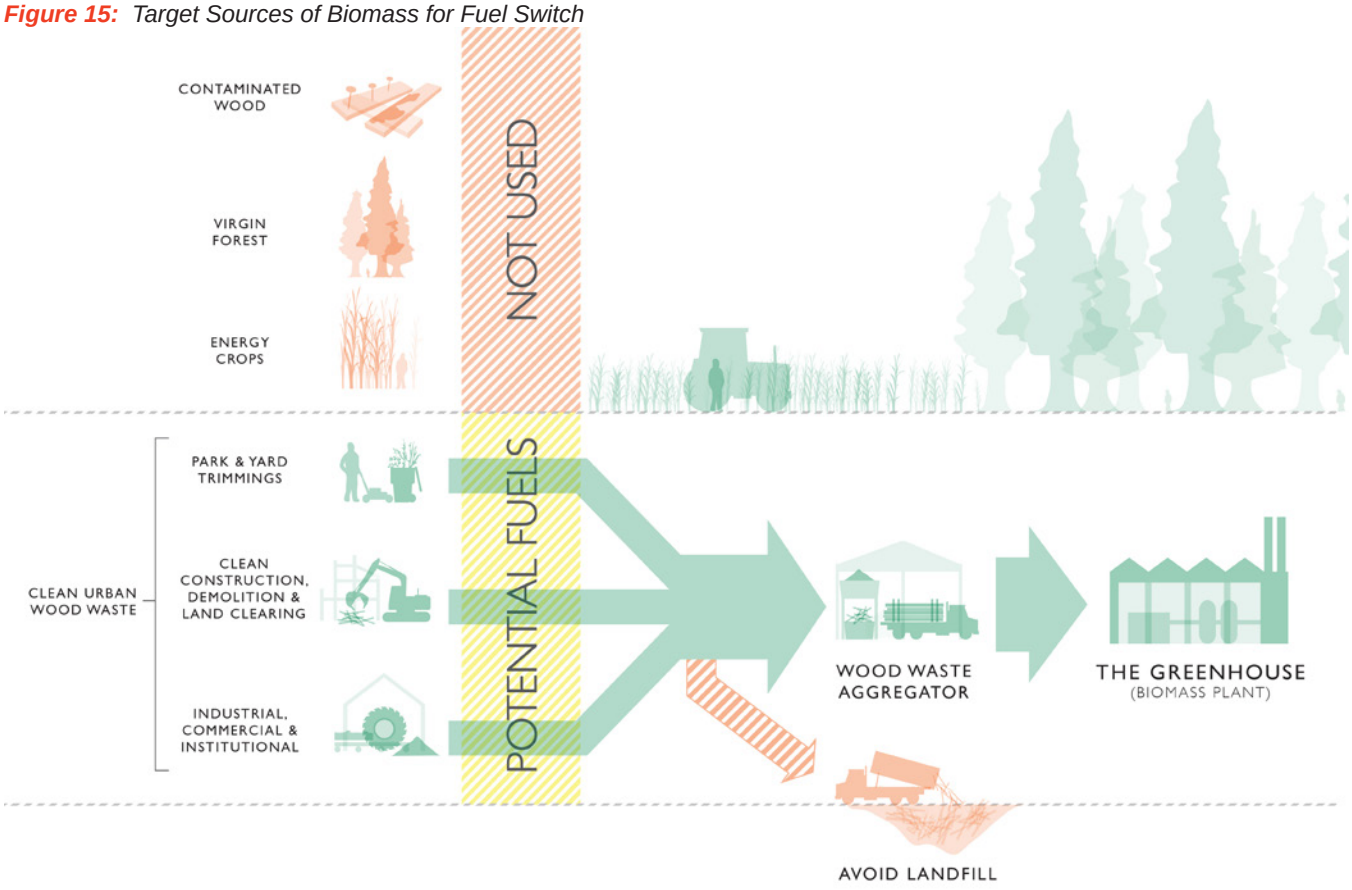
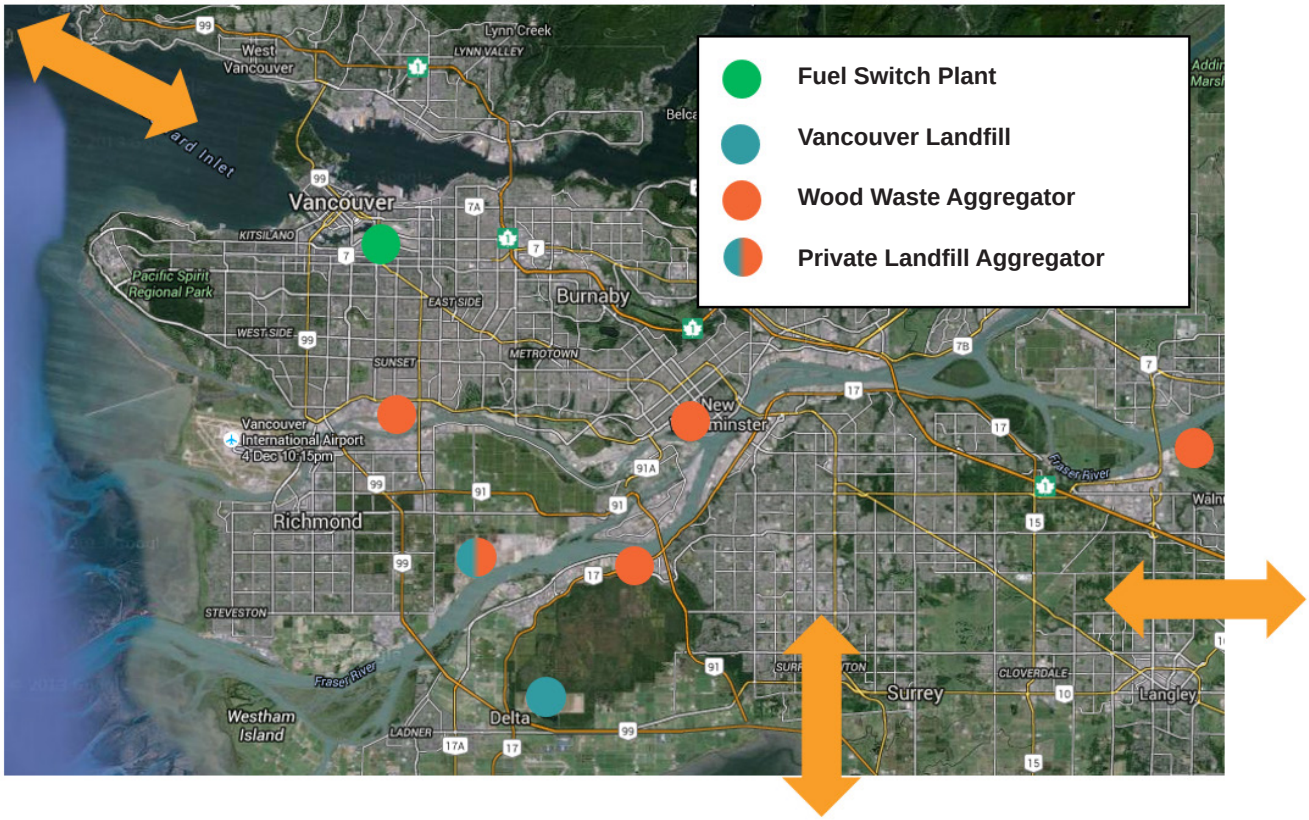


Figure 16: Approximate location of aggregators and landfills



6.2 LOCAL MARKET FOR URBAN WOOD WASTE

The Lower Mainland already has an existing supply chain in place for clean urban wood waste. There are several aggregators and landfills strategically located throughout the region to collect and market urban wood waste (Figure 16). Some aggregators collect wood waste directly from producers. Other aggregators and landfills simply take wood waste from third party haulers, charging these haulers a tipping fee.

In the past, waste wood has been both exported from and imported to the region for disposal, recovery or energy production. This includes both trade within B.C. and across the U.S. border. Historically, the scope and scale of trade depended on local supply conditions (e.g., housing starts), the cost of other fuels (gas and electricity), market conditions (e.g., demand from pulp and paper industries) and/or alternative disposal options or costs.

Only about 50% of the estimated local supply of clean urban wood waste is currently recovered and diverted from landfill. Starting in 2015, Metro Vancouver and member municipalities banned the disposal of clean wood waste to landfills. This is enforced by levying a 50% surcharge on the tipping fees for any loads with more than 10% clean wood waste.[27] This ban has encouraged more recovery and reuse. Examples of reuse include wood for structures, furniture making, and other consumer products. There is anecdotal evidence these markets are growing. However, there are still significant volumes of waste wood in the region that are not suitable for other uses and can be suitable for energy production. Some landfill operators are now contemplating investments in advanced sorting facilities to allow them to accept unsorted waste and to increase recovery of useful waste streams such as clean urban wood waste. These facilities would increase recovery and also free up space in landfills, extending their useful lifespan. Recovery of waste

27 http://www.metrovancouver.org/services/solid-waste/business-institutions/clean-wood-disposal-ban/Pages/default.aspx

streams such as clean urban wood waste could also create additional revenue streams in addition to tipping fees.

The existing demands for urban wood waste for energy production include low-carbon neighbourhood energy systems and industrial users such as pulp and paper plants, cement kilns, and commercial green houses. Currently, UBC is the only neighbourhood energy system in the region utilizing clean urban waste wood. However, there are several other planned neighborhood energy projects that are expected to use clean urban wood waste. These include energy systems at large institutions that also require steam, and other neighbourhood energy systems with no other suitable or economic sources of low-carbon energy. Table 19 shows project fuel volumes required for some existing and proposed neighbourhood energy systems in the region.

Local neighbourhood energy systems represent an important market to stimulate investments in enhanced collection, separation and recovery of clean urban wood waste. Many neighbourhood energy systems have formal requirements to supply low-carbon energy to meet franchise requirements, government targets, customer expectations and/or developer needs (e.g., Green Building certification). Neighbourhood energy systems offer potentially more stable demand for wood waste than industrial or commercial customers where operations and fuel decisions are more sensitive to external market conditions. Local neighbourhood energy systems can also help to reduce transportation costs and transportation emissions compared to more distant markets. Neighbourhood energy systems, without or without CHP, can also ensure maximum recovery of energy from wood waste. For example, in response to government policies BC Hydro has provided contracts to several biomass-fired electricity plants in B.C. However, few of these plants have heat recovery, meaning that only 30 - 40% of the energy content of biomass is converted to useful energy (i.e., electricity). In contrast, when used in a thermal only or CHP application, more than 70-80% of the energy content of biomass is converted to useable energy. In B.C., electricity produced from biomass displaces other green electricity sources. However, the heat produced from biomass typically displaces applications natural gas resulting in greater overall GHG reductions.

There is a finite amount of local clean urban wood waste. Some of the studies consulted for this report include:

- Report on Demolition, Land Clearing and Construction Material Recovery Facilities Study, for Metro Vancouver, by Gente Strategies (2015)
- Biomass Availability Study for District Heating Systems, for BC Bioenergy Network, by Envirochem (2012)
- An Information Guide to Pursuing Biomass Energy Opportunities and Technologies in British Columbia, for Province of BC and BC Bioenergy Network, by ENVIT Consulting (2010)

Table 19: *Existing and Contemplated Biomass-fired Neighbourhood Energy Systems*

PROJECT	STATUS	PROJECTED YEAR IN SERVICE	PROJECTED ANNUAL VOLUMES [BDT/yr]
UBC	Online	Currently in service	~ 15,000
Creative Energy Fuel Switch	In planning	2021	~ 90,000
Vancouver Children & Women's Hospital / Vancouver General Hospital	In planning	Unknown	~ 30,000
Simon Fraser University	In planning	2019+	~ 25,000
Surrey	Future proposed	2024+	~ 40,000
Total			~ 200,000

- 2014 CanBio Report on the Status of Bioenergy in Canada, by Renewed Energies (2014)

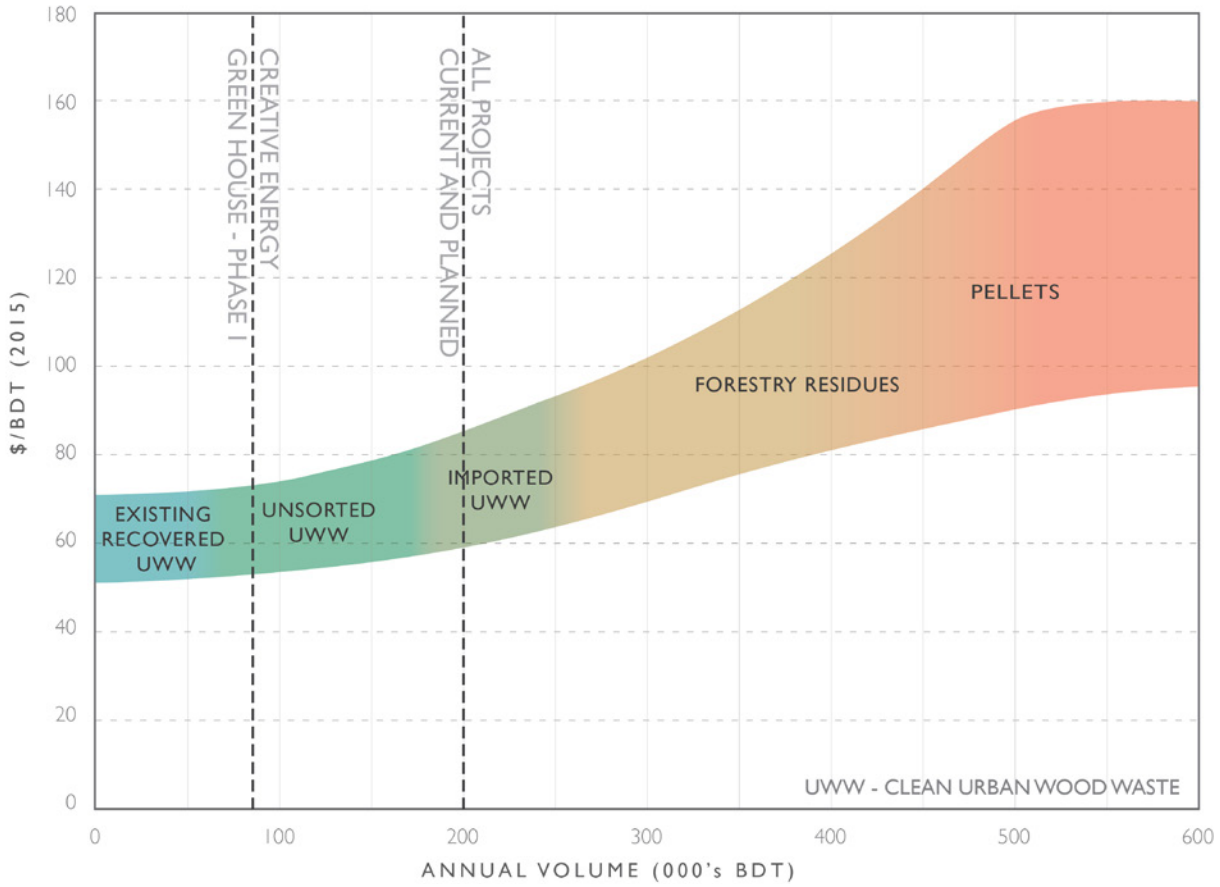
- 2011 – 2014 Metro Vancouver Waste Composition Studies

Some uncertainty exists regarding the total amount of urban wood waste and its delivered costs. However, there appears to be sufficient long-term local supply to support all of the currently existing and planned neighborhood energy systems intending to use urban wood waste, including the Fuel Switch project. Figure 17 shows a representative supply curve for biomass fuel developed by the study team. As noted previously, the Fuel Switch project could require up to 90,000 BDT/year. Combined with other existing and planned projects, the total potential demand for clean urban wood waste from neighbourhood energy systems in the region would be approximately 200,000 BDT/year. It is expected that this quantity of supply will require some additional investments in advanced sorting and recovery facilities in the region. Beyond these quantities there may also be opportunities to secure additional urban wood waste imported from neighbouring jurisdictions (e.g., northern Washington State) or to secure other forms of biomass fuel (e.g., more distant forestry residues, pellets and briquettes), albeit at higher expected costs.

Several trends are expected sustain the current volumes of urban wood waste in the region:

- As the Lower Mainland continues to urbanize around transit oriented developments, older single family homes and low density developments will continue to be demolished to make way for higher density development. Some of these structures are made from wood. Given the size and age of the existing housing stock, this demolition waste stream is

Figure 17: *Wood Waste Resource Supply Curve*



expected to provide a sustainable source of urban wood waste for some time to come with additional investments in advanced sorting and processing facilities.

- The BC Government is encouraging construction with wood. They have adopted a Wood First Act (2009) where public sector organizations are encouraged to construct with wood where practical. From an embodied energy and emissions perspective, wood has advantages over other materials such as concrete because it sequesters carbon as opposed to requiring carbon to create. The effect of this policy and other measures and market drivers toward promoting wood construction is an increase in wood waste from sawmill operations and construction-related activities.

Presently there is still considerable unsorted urban wood waste that ends up in landfills. Without long term certainty of a demand, fuel aggregators and landfill operators are reluctant to invest in infrastructure to sort and process this waste resource into a carbon neutral fuel for energy production. Based on experience in other jurisdictions and consultations with industry representatives, the Fuel Switch project could be an important catalyst for the upstream investments required to maximize diversion and recovery of clean urban wood waste in the region from landfill. Neighbourhood energy systems offer a significant and stable fuel demand to support such investments.

6.3 FUEL REQUEST FOR INFORMATION (RFI)

In order to validate the availability and cost of clean urban wood waste, the study team also conducted a fuel RFI. The base concept for the project will require up to 90,000 BDT of urban wood waste annually. Given expansion possibilities, the fuel RFI requested information on the supply of up to 150,000 BDT/yr. Respondents were instructed to provide a response for all or only a portion of this target amount. The higher fuel volume helps inform the strategy to upsize the plant or include a CHP component. CHP would increase the fuel requirements for the same thermal output.

Respondents to the RFI were required to provide costs and volumes for two different fuel specifications. Each fuel specification required common characteristics in terms of size (< 75 mm minus in all dimensions, average 25 mm minus, < 10% pass 3 mm mesh) and ash content (< 5%). However, the base and alternate fuel specification differ in terms of moisture content. The base specification calls for fuel with a moisture content up to 40% (annual average of 25%). The alternate specification calls for fuel with a moisture content up to 55% (annual average of 40%).

The fuel RFI confirmed the availability of sufficient urban wood waste. Table 20 summarizes the range of prices from the fuel RFI. The cost of fuel declines considerably with lower fuel specifications and higher allowed moisture content. Increased moisture content reduces plant efficiency somewhat, but this is more than offset by the lower costs of the fuel supply. An approximate relationship between moisture

Table 20: *Range of Prices in Initial Fuel RFI*

5 YEAR LEVELIZED COST (2020-2024) [$ per bone dry tonne] ($2015)		
	Base Specification Moisture Content: Maximum / Average 40% / 25%	**Alternate Specification** Moisture Content: Maximum / Average 55% / 40%
Low	$62	$58
High	$101	$70

content and efficiency is a 2% decrease in efficiency for every 5% increase in moisture content. This is not necessarily a linear relationship, e.g., at higher moistures say above 55%, efficiency may drop more rapidly. Boiler turndown (ratio of minimum to maximum operating capacity) is also affected by moisture content. At 50% moisture, a boiler may be capable of a 4:1 turndown but at 20% moisture same boiler may have be capable of a 6:1 turndown.

For the base case financial analysis, the study team used a conservative levelized cost of fuel of $77/BDT between 2020-2024 (equivalent to $14 per MWh of energy content). Fuel is then assumed to escalate at inflation beyond 2024. Over the entire 30-year analysis period, the levelized cost of fuel used for the financial analysis is $93/BDT (nominal $, including an allowance for inflation). Sensitivity analysis is conducted on alternate fuel price assumptions.

The final cost of fuel will be a significant factor in the plant cost and decision to proceed. It is expected that the bulk of the fuel will be secured for the plant prior to construction under long term purchase contracts or alternate business arrangements. A contract for at least 50% of the fuel is expected prior to any CPCN application, which would need to also include an outlook and strategy for the remaining fuel supply. The City controls some sources of urban wood waste and will likely need to play some role in the fuel supply strategy for the project. As with natural gas currently, the cost of wood waste would ultimately be a flow through to customers.

6.4 FUEL DELIVERY

The base specification for the fuel RFI assumed delivery by truck. This is currently the established mode of transportation for local urban wood waste. Respondents were also asked to provide information on possible delivery by barge or rail. Barge delivery would only be possible for sites on the Port lands, which were ruled out for the detailed feasibility study.[28] Rail delivery may be possible for the target site at 425 Industrial Avenue, which is adjacent to rail. However, none of the RFI respondents considered this feasible at the current moment and none provided a cost estimates for rail delivery. While rail delivery could reduce traffic impacts, fuel providers and rail experts consulted in this study expressed concern with the cost, practicality and reliability of rail delivery of local urban wood waste.[29] CN Rail, the owner of the rail network adjacent to the site, was contacted to determine their interest in facilitating rail delivery for the project. They expressed initial interest; however, to date they have not provided any quote on the cost or reliability of such a service. Rail delivery can continue to be explored in subsequent phases of the project development or as a future alternative to trucking. The remainder of this study assumes truck delivery of fuel.

The fuel costs used in the feasibility study include delivery costs. The preliminary plant concept assumes semi-trailers with a walking floor bed, or truck tipper technology to minimize unloading times. The typical arrangement is for rear unloading, however, other unloading arrangements are possible. Typical delivery trucks used in other similar projects (e.g., Seattle Steam) are WB-20 type trucks that are 16m long and unload from the rear with walking floors. The exact size and type of truck will be determined at the next stage of the project and will be informed by the plant design. Due to the size of this project, investment in a truck fleet specific for this project may be possible. This could allow for alternate unloading arrangements that optimize the plant design.

Trucks would typically be diesel powered; however, it may be possible to use natural-gas powered trucks to reduce GHG emissions (albeit small) and noise associated with trucking. However, members of the biomass fuel trucking industry have offered anecdotal evidence that while engine noise from diesel powered trucks is louder than natural gas powered trucks, noise from braking systems and the drive train

28 Barge delivery could reduce local truck traffic. However, barge delivery is most favorable for hauling large volumes over long distances. Because the plant would rely on local urban wood waste, barge delivery would not produce significant cost savings. There would also be some added complexity in loading and unloading barges.

29 The proximity of fuel aggregators and landfills to rail is also an important consideration in determining the viability and cost of rail delivery.

is common to both types of trucks. These non-engine noises can in fact be louder than engine-related noises. Other mitigation options for traffic impacts include scheduling deliveries during night-time or off peak traffic times.

The base concept assumes 36 hours of on-site fuel storage. This implies up to 30-40 trucks per day would be required during peak operation, assuming deliveries only on weekdays and half days on Saturdays. The range in truck numbers reflects the range of expected moisture content of fuel over the year. There would also be fewer trucks in shoulder seasons and summer. Many plants typically have 3 days of storage to allow full operations over a long weekend without any fuel deliveries. The analysis assumes less on-site storage for the Fuel Switch project given site constraints and land costs.

Bunt and Associates completed a preliminary transportation review for the 425 Industrial Avenue site, and the team also had multiple conversations with the City's Transportation Department during the study. The site is adjacent to major trucking routes that see a large amount of heavy vehicle traffic to the Ports. The proposed routing to the site would be from Clark Drive, which is one of the City's designated trucking routes. The City's two-way truck count over a 12-hour period (6:00 AM to 6:00 PM) for Clark Drive is estimated to be 1,200 trucks.

From Clark the most likely route for trucks to each the plant site would be via Great Northern Way inbound and Terminal Ave outbound as shown in Figure 18. Once on the site, the trucks would enter from Scotia on the northern edge of the property and exit the site south bound on the eastern edge. The transportation review identified one area on the outbound route that would require a change to the existing parking regulation. As shown in Figure 19, the street parking on the east side of Station Street would need to be removed for trucks to turn right onto Terminal.

6.5 GHG NEUTRALITY OF URBAN WOOD WASTE

Under the BC Greenhouse Gas Target Reduction Act (2007) biomass fuel is exempt from carbon taxes and the additional offset requirements for Public Sector Organizations. This means that heating service generated from urban wood waste has no carbon liabilities (carbon tax or requirement for offsets for PSOs).

Biomass is a large category and there is some controversy in GHG accounting standards related to some sources of biomass. However, under all GHG accounting protocols reviewed by the study team, local clean urban wood waste is the least controversial and is considered GHG neutral in all standards.

Table 21 below summarizes GHG accounting protocols that treat biomass and in particular clean urban wood waste as carbon neutral.

6.6 GHG EMISSIONS FROM FUEL DELIVERY

One of the other concerns sometimes raised with the GHG neutrality of urban wood waste is the GHG emissions associated with fuel delivery. In reality, the additional GHG emissions from transportation are small in comparison to the emissions avoided from using urban wood waste vs. natural gas. Assuming an average delivery distance of 100 km for urban wood waste, the extra emissions from fuel delivery would represent about 0.6% of the emissions avoided from the use of the fuel. This estimate assumes 100% of the emissions from fuel delivery are incremental to the use of this fuel for the plant. In reality, wood waste would still need to be transported for other uses or disposal. It is also important to note there is uncertainty in long-term GHG emission factor for natural gas with the growing reliance on unconventional sources such as shale gas.

Figure 18: Fuel Delivery Route Scenario

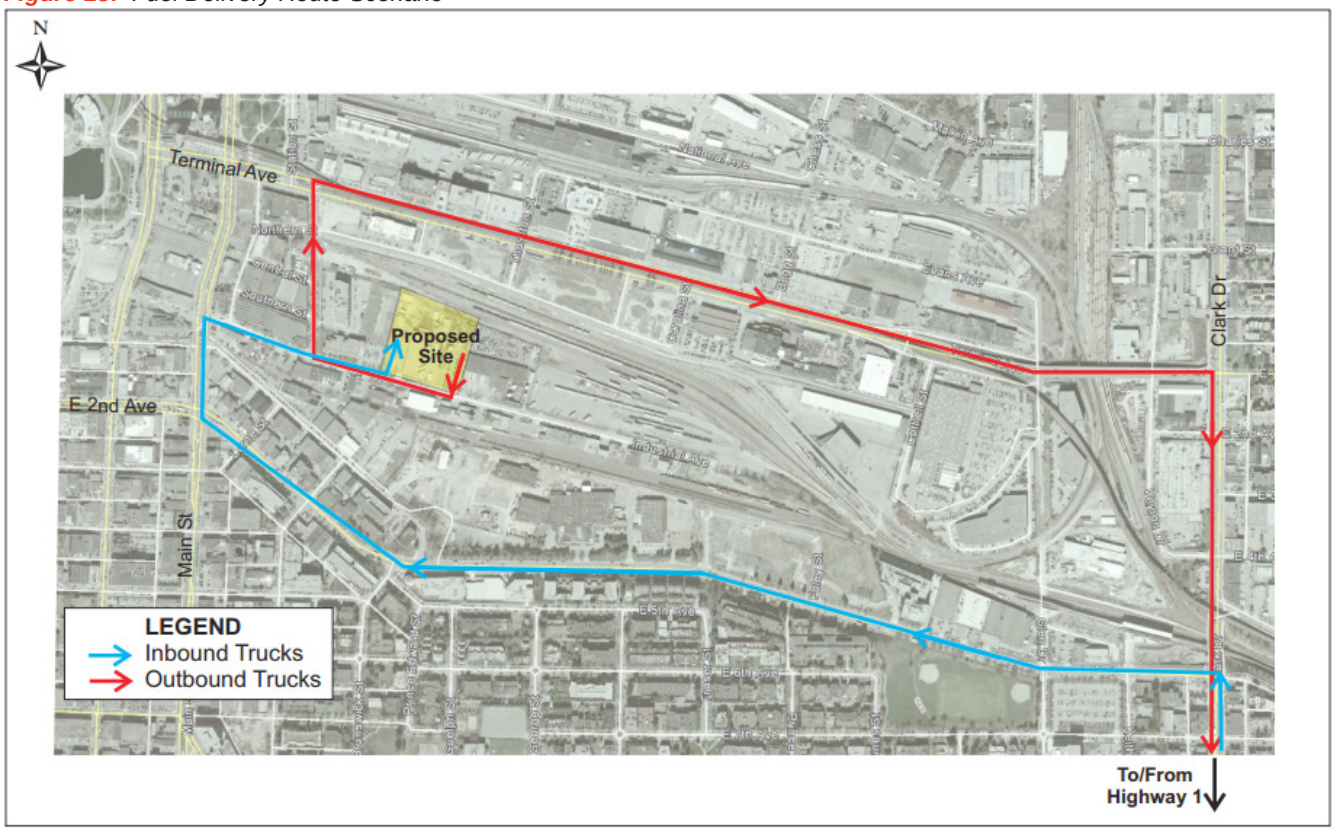


Figure 19: Proposed Station Street Parking Removal

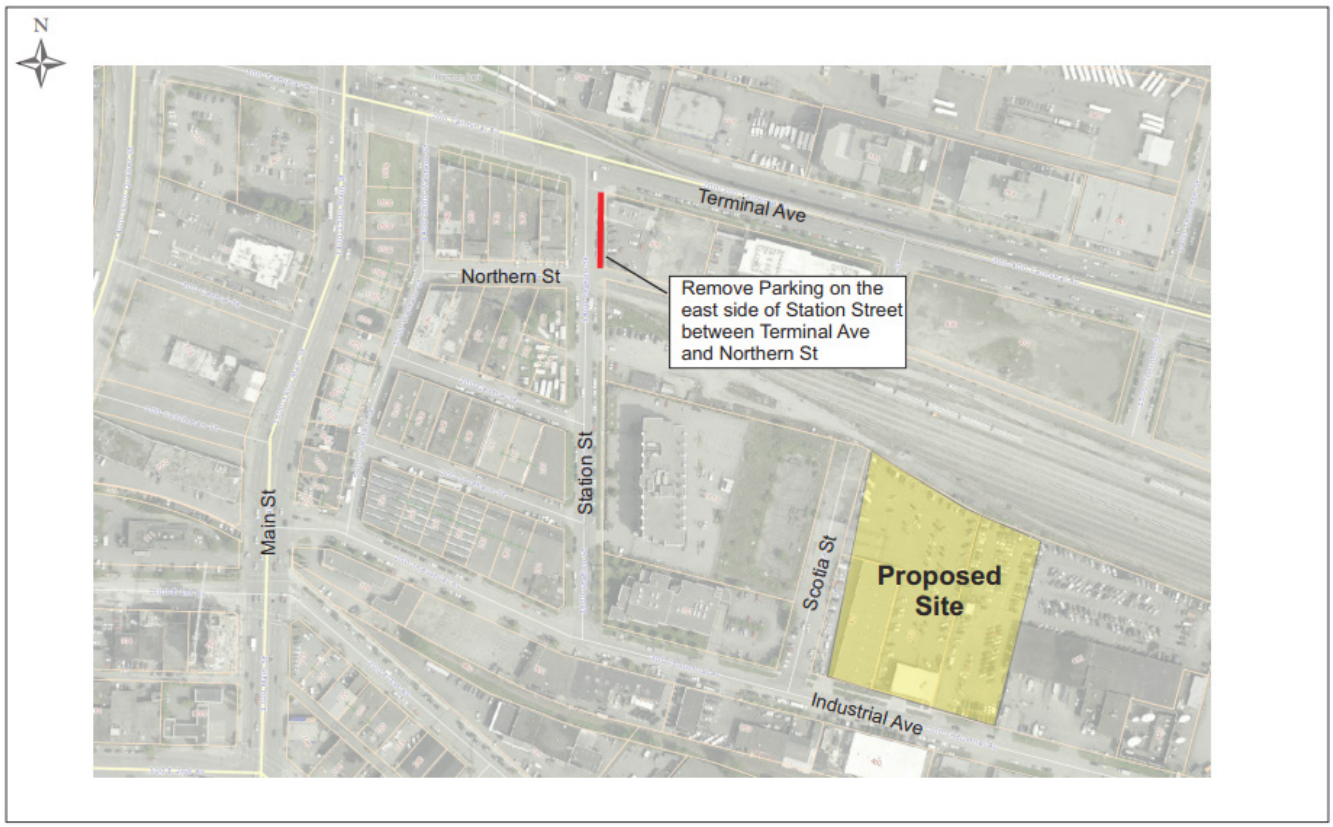


Table 21: *Standards Treating Urban Wood Waste as Carbon Neutral*

		REFERENCE
IPCC	Intergovernmental Panel on Climate Change	IPCC Guidelines for National Green House Gas Inventories. Chapter 2: Stationary Combustion (2006) [i]
ISO	International Standards Organization	ISO 14064 Greenhouse gases — Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals (2006) [ii]
IEA	International Energy Association	Website with technical information [iii]
EIA	US Energy Information Association	Website with technical information [iv]
WRI **C40** **ICLEI**	Global Protocol for Community Scale Greenhouse Gas Emission Inventories	An Accounting and Reporting Standard for Cities [v]
CAN	Government of Canada	Technical Guidance on Reporting Greenhouse Gas Emissions [vi]
BC	Government of British Columbia	2014 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions Including Guidance for Public Sector Organizations, Local Governments and Community Emissions [vii]
CoV	City of Vancouver	Neighbourhood Energy Centre Guidelines [viii]

i http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf
ii https://www.iso.org/obp/ui/#iso:std:iso:14064:-1:ed-1:v1:en
iii https://www.iea.org/publications/freepublications/publication/essentials3.pdf
iv http://www.eia.gov/energyexplained/index.cfm?page=biomass_wood
v http://ghgprotocol.org/files/ghgp/GHGP_GPC.pdf
vi http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=47B640C5-1&printfullpage=true
vii http://www2.gov.bc.ca/assets/gov/environment/climate-change/policy-legislation-and-responses/carbon-neutral-government/measure-page/2014_bc_best_practices_methodology_for_quantifying_greenhouse_gas_emissions.pdf
viii http://vancouver.ca/home-property-development/neighbourhood-energy-strategy.aspx

7. SITE CONCEPT AND BUILDING COST

Section 3 of the report summarizes the site selection process and target site. This section discusses a preliminary concept for the energy centre, together with an estimate of building costs for the financial analysis.

7.1 SITE BOUNDARIES AND EXPANSION POTENTIAL

The target site at 425 Industrial Avenue is L-shaped. It is approximately 0.65 hectares in size. Due to the geometry and size of this parcel, it is not adequate to accommodate the base concept. The boundary between 425 and 455 Industrial Avenue would need to be adjusted. The City owns both parcels. About one-third of the parcel at 455 Industrial Avenue would need to be subdivided and amalgamated with the parcel at 425 Industrial Avenue. The boundary change would not affect the existing structures on 455 Industrial Ave. Each property currently has a different zoning designation. The property at 425 Industrial Avenue is zoned I-2, while the property at 455 Industrial Avenue is zoned I-3[30]. The City has advised that 425 Industrial Avenue would likely be considered I-3 zoning once amalgamated with a portion of 455 Industrial Avenue. The energy centre is a permitted use for both land parcels.

The financial analysis in this study considers only a Phase 1 plant (65 MW thermal-only urban wood waste plant). However, the target site was also selected in part because of its future expansion potential (to the remainder of 455 Industrial Avenue). Expandability is an important consideration given the project size, likely growth in demand for low-carbon energy, limited availability of land, and large new interconnection required. The scope of a possible Phase 2 of the Fuel Switch project is not defined (technology, equipment size, etc.). However, the available area at 455 Industrial could allow additional thermal capacity or CHP. The proposed interconnection could accommodate up to 110 MW of thermal delivery capacity to the core or new customers along the proposed route. The plant expansion may also need to accommodate other uses, including ongoing recycling operations. However, it is expected these operations could be accommodated together with additional energy production through a more efficient design for 455 Industrial Avenue.

Figure 20 shows the tentative site boundaries and proposed areas for Phase 1 and a potential Phase 2 of the Fuel Switch project. The proposed layout and orientation for the Phase 1 equipment contemplates the potential for a future expansion and also the possibility to utilize rail either as a primary or secondary means of fuel delivery at some point. The site concept is preliminary and only intended to support proof of concept and costing for feasibility purposes. Further optimization of the layout of Phase 1 is expected in the detailed design phase.

7.2 EXISTING AND SURROUNDING LAND USES

The two parcels are owned by the City. They are currently housing two separate active operations (one on each parcel). Busters Towing operations is on 425 Industrial and uses the space for tow truck parking and offices and it serves as the City impound lot for towed vehicles and an overflow for Busters commercial towing operations. 455 Industrial is used jointly by Recycling Alternatives, and United We Can (a social enterprise bottle depot).

Immediately adjacent to the two parcels are:

- private business (multi-unit office / warehouse building) and privately held land (currently vacant lot) to the west,
- communications facility (Telesat Canada, Government owned and operated satellite service providers) to the east,

30 I-2 and I-3 zoning permit non-residential uses including utility and communication, manufacturing, cultural and recreation, office, service. A complete list of acceptable uses can be found at these links, http://former.vancouver.ca/commsvcs/BYLAWS/zoning/i-2.pdf, http://former.vancouver.ca/commsvcs/BYLAWS/zoning/i-3.pdf

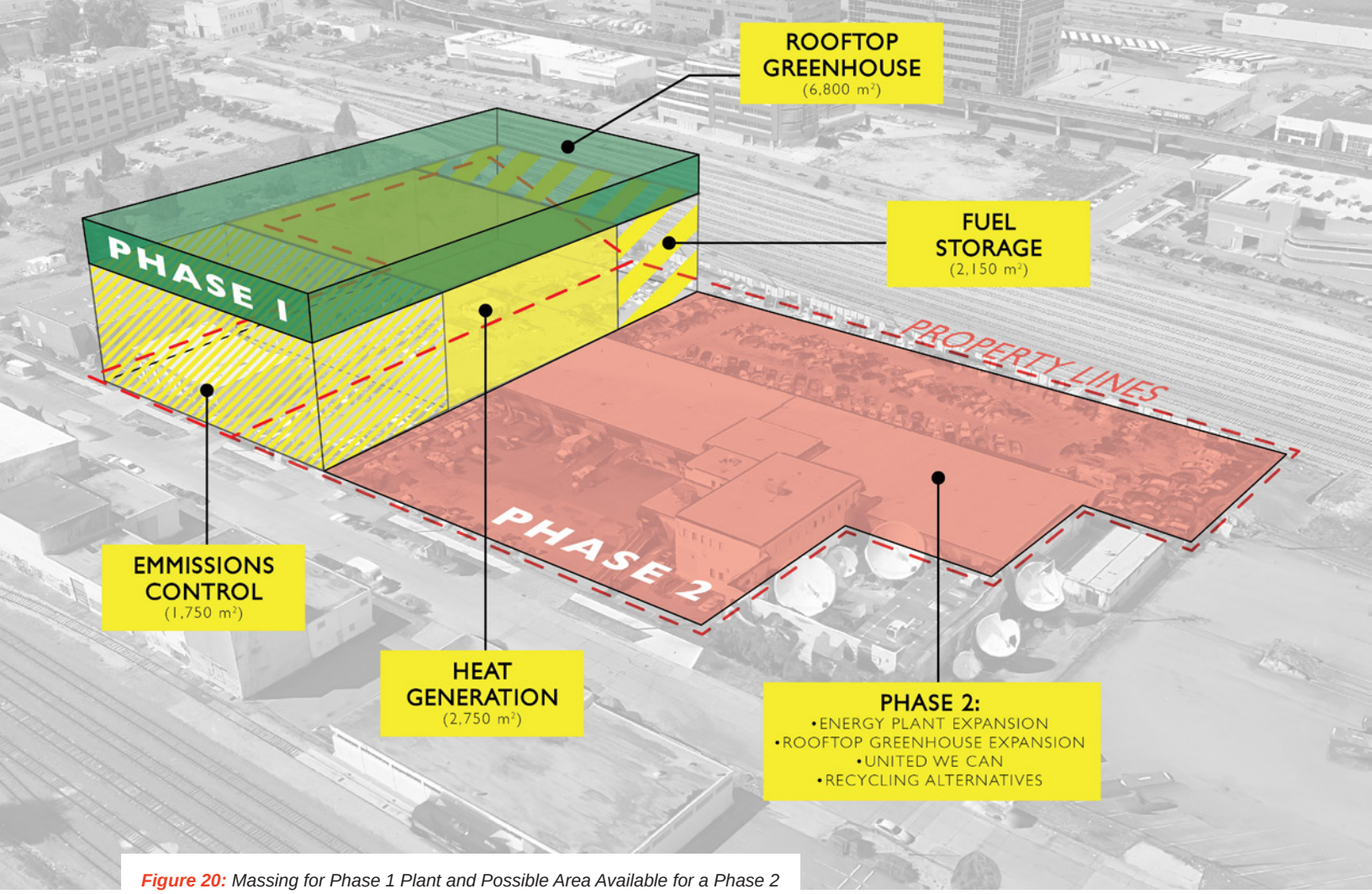


Figure 20: *Massing for Phase 1 Plant and Possible Area Available for a Phase 2*

- light industrial businesses and commercial operations to the south, and
- a railyard to the north.

Railyards surround the site to the north and the south providing a buffer between the Fuel Switch plant and other residential, institutional, and commercial buildings. Beyond the railyard to the north are some educational facilities and commercial operations as well as the elevated SkyTrain where the interconnection optimization is proposed. Figure 21 shows the target site together the surrounding context.

7.3 FUEL DELIVERY AND STORAGE

The preliminary plant design assumes approximately 36 hours of fuel storage on-site. This storage would be enclosed within the building and this enclosure is included in the building cost for the energy plant. The preliminary concept assumes truck delivery of fuel via Industrial Avenue and Scotia Street. Rail delivery was contemplated but ruled out for the preliminary plant design because of logistical and institutional challenges. It could be possible to accommodate rail delivery in future. The final plan for fuel delivery and handling within the site will need to be addressed at the next stage of more detailed design.

7.4 PRELIMINARY BUILDING DESIGN ("THE GREEN HOUSE")

The proposed building, referred to simply as The Green House, includes the energy plant, an innovative rooftop farm, and an interpretive centre. The preliminary design was developed by Bjarke Ingels Group with input from Henriquez Partners Architects. The design was informed by representative equipment layouts from the technology RFI (e.g., space and height requirements and equipment layout), local context, and other examples of rooftop farms.

Figure 21: *Target Site and Surrounding Context*

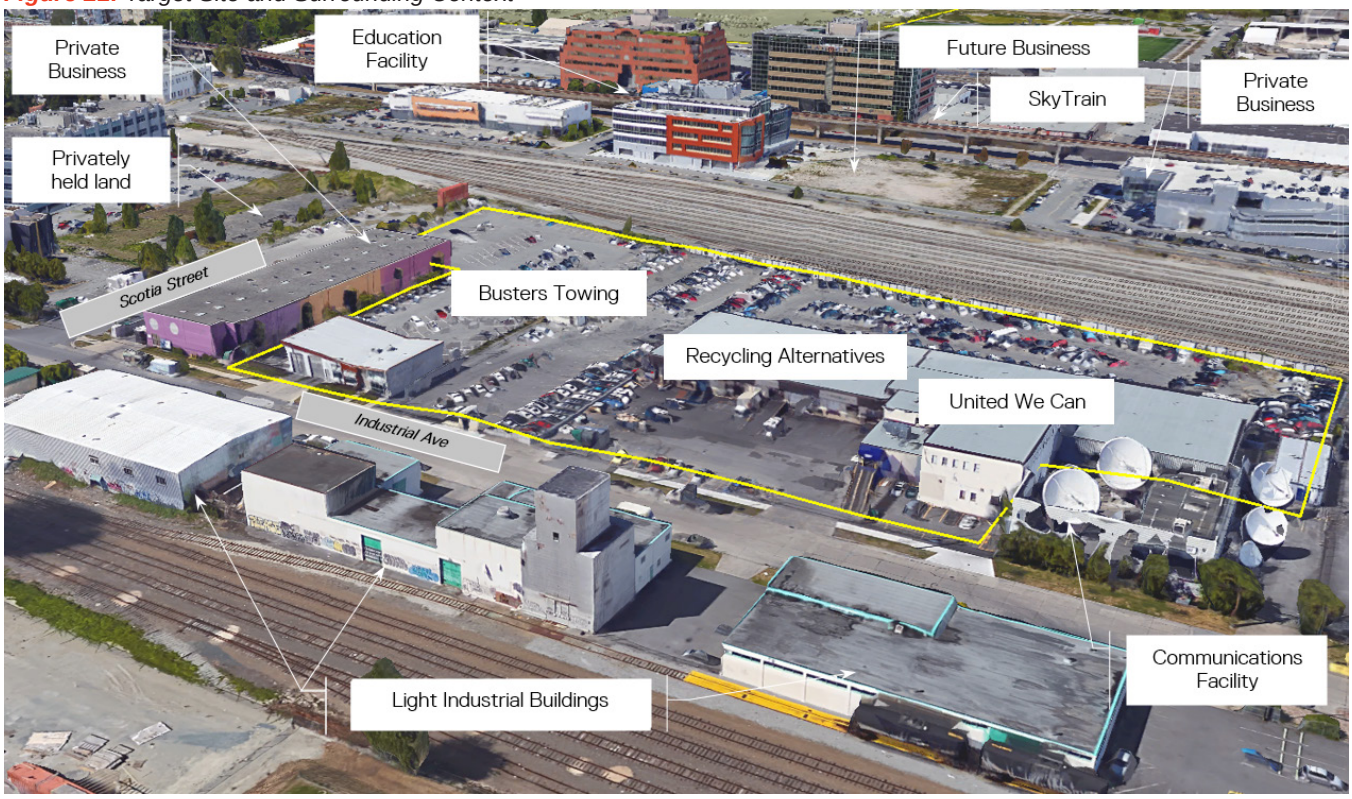


Figure 22 shows three preliminary renderings of the Green House from different angles. These reflect both Phase 1 and a potential Phase 2. They are intended as proof of concept only and also to support conversations on a long-term vision for the project. The costing for the financial analysis in this study reflects only the Phase 1, which represents approximately half of the total plant shown in Figure 22.

The preliminary design allows for open views into the plant to daylight infrastructure as public art that has aesthetic and awareness value beyond its utilitarian purpose. This is consistent with other plant designs such as the University of Chicago's South Campus Chiller Plant and the UBC Bioenergy Research Centre, as well as public art incorporated into the City's sewer heat recovery plant for SEFC. The design conforms to the City's Neighourhood Energy Centre Guidelines, which require consideration of neighbourhood fit.

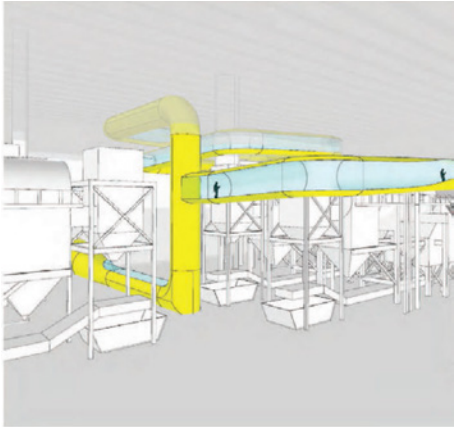
The building and use fit within the current zoning for the site.[31] The proposed height of the building is 30.5 m, which includes the height of the rooftop farm (approximately 7.6 m) but does not include the stacks, which could add another 7.6 m above the top of the farm. These are preliminary estimates that will need to be confirmed in final design.

According to the I-3 zoning for the site, the maximum height permitted is 18.3 m; however, with approval from the Director of Planning or the Development Permit Board the maximum height can be increased up to 30.5 m. The stack is not included in these height limits. The Zoning Bylaw allows the Director of Planning to provide height exemptions for stacks. The study team has met with the City to discuss the proposed height and use. The City has suggested that based on current zoning and proposed plant design, the project would not require a rezoning application, only a development permit and building permit.

31 At the beginning of this study, False Creek Flats Zoning did not contemplate urban agriculture as a compatible land use. However, in February 2016, Council adopted a new policy that allows urban farming in I-2 and I-3 zones to proceed without a rezoning to a maximum size of urban farm up to 7,000 m^2, which is just above the expected Phase 1 area of the proposed rooftop farm.

Figure 22: *Preliminary Renderings for the "Green House"*

Figure 23: *Interpretative Centre Concept*



This greatly simplifies and accelerates possible implementation of the project. However, as noted above some adjustment would be required to the property line between 425 and 455 Industrial Avenue.

The elevation of the target site is ~4 m above sea level. The City's recommended construction level to accommodate flood and climate change impacts within the Flats and NEFC is +4.5 m. This difference was not considered significant for the purposes of a preliminary design concept. Additional mitigation measures to account for flood construction levels will need to be considered at a future stage of more detailed design. Due to the uncertainty around the final design of the plant, the relatively small difference between the current elevation and the City's flood construction levels, and expected flood mitigation costs for the building the analysis assumes any costs for flood mitigation would be absorbed in the contingency assigned to the building and plant capital cost estimates.

The proposed rooftop farm is intended to provide the following benefits for the Fuel Switch project:

- share land costs and property taxes for the energy plant,
- support the enhanced aesthetic vision for the building,
- provide additional community benefits including local food, education, green tourism, and other spin offs, and
- capture potential synergies between energy and food production, including waste heat recovery and disposal of residual organics from growing operations.

The rooftop farm is modelled on recent projects implemented by Lufa Farms in greater Montreal (Figure 24 and Figure 25). Lufa produces about 200 tonnes of produce annually using just over 70,000 sq ft of farm space in Montreal. Lufa has been operating rooftop farms since 2011 and has developed a system for minimizing inputs and maximizing production within their green houses. Co-locating a rooftop farm with the energy plant provides opportunities for waste heat capture to benefit the rooftop farm, as well as integrated management of green waste from the farm. The project would provide additional employment in an innovative sector, and would increase Vancouver's local food security and resiliency.

The rooftop farm is intended to be a self-supporting business, covering its own building costs, equipment costs, and ongoing operating costs. At full build out, the rooftop farm could produce up to 400 tonnes of vegetables annually, enough to meet the annual needs of 10,000 people. Besides contributing to aesthetic improvements and additional community benefits, the financial analysis for the Fuel Switch project reflects expected benefits from sharing land costs, property taxes and some building services.

An Interpretative Centre is also contemplated as part of the preliminary design (Figure 23). The preliminary concept involves a pipe that would allow visitors to pass through the building without disrupting operations of either the energy plant

Figure 24: *Interior of a Lufa Rooftop Farm, Laval, Quebec*

Figure 25: *Exterior of Lufa Rooftop Farm, Laval, Quebec*

Table 22: Building Cost Estimates for Energy Plant

	($2014)*	REFERENCE
Utility-grade Building & Foundations [$000s]	4,600	Summary of Technology RFI responses
Additional Architectural Premium [$000s]	10,000	
Base Estimate [$000s]	14,600	Before taxes and contingency (added separately in financial model)
Including Contingency and Taxes [$000s]	18,200	
Building Area [m²]	6,600	Included enclosed fuel storage
Unit Cost [$/m²]	2,800	

** Costs include equipment and labour as well as soft costs (design and construction management). Contingency, taxes, or grants are not included.*

or the rooftop farm. This pipe would include interpretive information and the path would help to illustrate the carbon cycle (from growing biomass to use of residues in energy production).

7.5 BUILDING COST ESTIMATES

A preliminary estimate of building costs was developed using information gathered in the technology RFI with some allowance for an architectural premium over a simple utility-grade building. The team drew on information from other local energy centres. The preliminary estimates were also reviewed with a quantity surveyor.[32]

The base cost estimates used in the financial analysis are shown in Table 22. Preliminary building costs are considered Class 4 estimates only. An architectural contingency of $10 million was added to the estimate for a utility-grade building, and an additional contingency of 20% was applied to the total base estimate (including PST). The final building design is uncertain and will also depend on the final technology selection.

Only building costs allocated to the energy plant are included within the financial analysis for this study. These include a share of:

- labour and materials,
- shell (i.e. walls and roof of energy plant only, including fuel delivery and storage area),
- site services (water, sewer, electrical, gas, etc.),[33]
- concrete footings, and
- soft costs (design and construction management).

Incremental costs for the rooftop farm and interpretative centre are not included in the capital cost estimates for the energy plant. The rooftop farm is expected to cover its incremental building costs. A funding and operating model for the interpretive centre has not been confirmed and is beyond the scope of this feasibility study. Sources of funding could include a mix of grants, sponsorships, partnerships, and the utility. One example of a potential partner to program and operate the interpretative centre is Science World.

32 A quantity surveyor was consulted later in the feasibility study. Their analysis is provided in a separate report. They estimated a higher base cost for the building (before contingency), but this was also based on a higher level of detail. The estimate from the quantity surveyor was within the range of earlier cost estimates, which included a larger contingency. As a result, no changes were made to the estimates in the financial analysis. The quantity surveyor report also provided estimates for the incremental costs of the rooftop farm and interpretative centre. These were used to help inform estimates of property taxes and also the allocation of shared building services.

33 Based on input from quantity surveyor, site service costs for the building were allocated 80% to the energy plant and 20% to the rooftop farm.

8. FINANCIAL AND GHG ANALYSIS

8.1 BASE CASE COST OF SERVICE FOR FUEL SWITCH

The following sections describe the base case assumptions for the cost of service of the Fuel Switch. The cost of service (or revenue requirement) for the Fuel Switch includes the cost of delivery (including losses) to the existing Beatty Street plant, which is the reference point for status quo costs and different alternatives. The direct cost of service for the Fuel Switch does not include ongoing downstream costs of the existing network, existing steam plant (which continues to be required for peaking and back-up) or new hot water networks. These costs are common to all scenarios and are also reflected in the retail rate comparisons under various alternatives. Assumptions for additional sensitivity and scenario analysis, including possible optimizations, enabling strategies and project alternatives, are discussed in later sections of the report. Important updates since the bulk of the feasibility analysis was completed are also noted where relevant.

8.1.1 Demand / Production Assumptions

Phase 1 of the Fuel Switch is sized to meet baseload demands of existing steam customers as well as projected development in NEFC and South Downtown.[34] Existing steam sales are approximately 385,000 MWh / year under average weather. Accounting for losses in the steam network, the Beatty Street plant produces about 420,000 MWh of gas-fired steam per year under average weather. The baseload production of the existing steam customers is about 322,000 MWh (77% of annual production). For the purposes of the base case analysis, existing steam loads are assumed to remain constant. This is a reasonable assumption based on historical consumption patterns as periodic and lumpy upgrades in building envelopes have been offset by other changes in building consumption patterns (e.g., mix of uses) and modest customer additions to the core.

The demands for NEFC and South Downtown are based on development projections, expected energy use intensity, and expected carbon performance requirements (0.07 tonnes GHG per MWh of heat sales). Demand from NEFC and South Downtown is projected to increase from 2020 until expected build out around 2030. At build out, NEFC and South Downtown represent about 17% of the anticipated Fuel Switch production.

Expected output of the Fuel Switch is summarized in Table 23. As shown, the expected output of the Fuel Switch also accounts for energy losses between the new plant and the existing steam plant at Beatty Street (about 1% of annual energy transfers). Output increases over time to reflect the development timelines for NEFC and South Downtown. To the extent additional customers are secured or development in NEFC and South Downtown occurs more quickly, production from the Fuel Switch would ramp up more quickly. Increased utilization of the plant earlier in the analysis period will reduce any financial gap, all things being equal. Annual output of the Fuel Switch plant is constrained by plant capacity (65 MW), combined heating load duration curve of projected customers, and an allowance for planned and unplanned maintenance (4 weeks). The expected capacity factor for the plant (annual production divided by theoretical maximum production) is about 69%. At full build out of NEFC and South Downtown and assuming no change in core steam demands, the Fuel Switch would displace about 77% of the annual steam production required from the existing Beatty Street plant.

34 As noted elsewhere in this report, the NEFC Decisions of the Commission issued since the bulk of this feasibility study was completed have created new uncertainty over the long-term demands for NEFC and South Downtown neighbourhoods.

Table 23: Fuel Switch Steam Production Assumptions, Select Years

	2020 [MWh]	2025 [MWh]	2030 [MWh]
Steam Produced at Fuel Switch Plant	351,000	364,000	393,250
Steam Delivered to Beatty Street Plant	347,500	360,400	389,300

Table 24: Fuel Switch Wood Waste Consumption and Costs, Select Years

	2020	2025	2030
Plant Output [MWh]	351,000	364,000	393,250
Efficiency		80.8%	
Wood Waste Input [MWh]	434,400	450,500	486,700
Wood Waste Fuel Cost [$ per MWh]	$13.51	$14.92	$16.47
Annual Wood Waste Cost [$000s]	5,871	6,722	8,018

Table 25: Fuel Switch Electricity Consumption and Costs, Select Years

	2020	2025	2030
Electricity [MWh]	9,793	10,156	10,972
Electricity Cost [$000s]	977	1,175	1,472

8.1.2 Wood Waste and Electricity Input Costs

Annual wood waste costs for the Fuel Switch are a function of assumptions for plant output, fuel efficiency, and fuel input costs. Assuming a plant efficiency of 81%, annual wood waste consumption could reach 487,000 MWh once the plant reaches full production in 2030. Drawing on the fuel RFI and other research, baseline wood waste costs start at $13.51 per MWh in 2020 (equivalent to $74 per BDT) and then escalate at inflation. By 2030, annual wood waste fuel costs would reach over $8 million (Table 24). The plant will also require electricity for controls, fuel handling, lighting, and other functions. Electricity consumption is assumed to be 2.8% of steam output, or nearly 11,000 MWh per year by 2030. Annual electricity costs for the plant are projected at $1.5 million by 2030 (Table 25). This reflects project rates for BC Hydro's Large General Service.

8.1.3 Non-Fuel Operations and Maintenance

Operators

Creative Energy currently has 12 operators for the Beatty Street plant. Using comparables for other plants, Fosdick & Hilmer estimate the Fuel Switch plant would require 12 incremental full-time equivalent (FTE) operators. This assumes some cross-training of operators between the two plants, so staff can support either plant as needed at certain times of the year. There may be opportunities to reduce incremental operators but this will require further due diligence and discussions with the BC Safety Authority. Total operator costs for the Fuel Switch are $1.4 million in 2020. Operator costs are escalated at 2% per year.

Building, Plant and Interconnection Maintenance

Annual building maintenance is estimated at 2% of installed costs or $309k in 2020. Annual plant maintenance is estimated at just under 2% of installed costs or $1.4 million in 2020. This includes an allocation of $50,000 per year for maintenance of a CEMS. Interconnection maintenance is estimated at 0.5% of installed costs or $124k in 2020. All maintenance costs are escalated at 2% per year.

Insurance

Insurance is estimated at 0.2% of total capital costs or $256k in 2020. Insurance costs are escalated at 2% per year

Table 26: Summary of Non-Fuel O&M (Excluding Property Taxes), Select Years

	2020 [$000S]	2025 [$000S]	2030 [$000S]
Operator Cost	1,351	1,492	1,647
Building Maintenance	389	429	474
Plant Maintenance & CEMS	1,398	1,543	1,704
Interconnection Maintenance	124	137	152
Insurance	247	273	302
Corporate Overheads	175	194	214
Land Rent*	637	637	776
Total	4,322	4,706	5,268

** Net of contribution from rooftop farm.*

Corporate Overheads

Incremental corporate overheads are estimated at $175k per year. This is equivalent to approximately one management-level position to oversee the plant. There is no reduction or re-allocation assumed for existing corporate overheads related to the existing plant. Overheads are escalated at 2% per year.

Land Rent

The City is expected to retain ownership of the land for the plant and Creative Energy would pay annual rent under a long-term lease. Based on input from the City, current value for industrial land in the flats was assumed at $1,000 / m^2. The annual rent (before any enabling tools or alternate lease arrangements) assumes a cap rate of 7.2%. Assuming a site area of 9,300 m^2 for the Phase 1 plant, the annual land rent in 2020 is $740k. However, 15% of the land rent ($100k in 2020) is allocated to the rooftop farm, leaving $640k to be recovered from the Fuel Switch pro forma. Land rent is fixed for periods of 10 years, with a step increase at the beginning of each 10-year period to reflect cumulative escalation in land value of 2%/year.

Consumables

The Fuel Switch plant would also consume water and chemicals for water treatment. However, for simplicity these consumables are excluded from the Fuel Switch costs. These costs are already part of existing steam costs and have been excluded from avoided costs. These costs would also represent a relatively small portion of the total cost of service for the Fuel Switch.

Table 26 summarizes total non-fuel O&M assumptions for the Fuel Switch pro forma, excluding property taxes. These are described in the next section.

8.1.4 Property Taxes

Under current policies and mill rates, property taxes represent a significant portion of the Fuel Switch costs. For the purposes of this feasibility study, the base case for property taxes is calculated using the installed costs for taxable assets and the Utility Mill Rate (Property Class 2). The relevant project assets are the building, land, and the new interconnection. Only the portions of the building and land allocated to the energy production plant are considered in the Fuel Switch pro forma.

Property taxes are difficult to estimate. There is normal uncertainty in the future assessed value of land. But there is also considerable uncertainty in the assessed value of the building and interconnection. This is due in part to the current lack of guidance from the Assessment Authority on valuation methods for linear infrastructure (the interconnection). There is also some uncertainty about whether the new interconnection will in fact trigger additional property taxes under the terms of Creative Energy's existing Municipal Access Agreement, which provides a credit towards the Municipal Access Fee (calculated based on gross utility revenues) for any property taxes on distribution assets. The incremental property taxes from the brand new and lengthy interconnection could exceed the available credit.

A conservative assumption of full property taxation has been used in the base case analysis. All property taxes are based simply on installed costs of relevant assets and estimated land value provided by the City. Table 27 summarizes the estimated property taxes for select years. It is important to note existing steam customers already pay full property taxes on the current steam plant, which will be retained for ongoing peaking and back-up. Property taxes for the Fuel Switch, which is not required for energy or capacity per se but to reduce GHG emissions, are entirely incremental for existing customers. Further, the utility mill rate, which is unique to B.C., is the highest mill rate in Vancouver, higher than major industry (Property Class 4) and more than three times higher than light industry or business classifications (Property Classes 5 and 6, respectively, which are the most likely alternate uses of the target site for the project. Vancouver's general purpose tax levy represents about 67% of the utility mill rate, the remainder is primarily for schools and transit.

Property taxes are discussed further under possible enabling strategies for this project.

8.1.5 Depreciation, Financing Costs and Income Taxes

Table 28 and Table 29 summarize the total base case capital cost assumptions in the Fuel Switch pro forma. The source of these estimates is described in earlier sections of the report. Capital cost estimates are inflated to 2020 which is the in-service date for the project within the current pro forma. The pro forma also adds an allowance for PST and contingency (where these are not already included in base estimates). The contingency is also intended to capture development costs. On average, about 50% of capital costs are expected to be subject to PST, so PST of 7% is applied to 50% of all cost estimates. For the purposes of the pro forma, IDC is estimated assuming a weighted average construction financing period of 1.5 years for all assets and a debt rate 4.5%.

To estimate an annual cost of service for the Fuel Switch, upfront capital costs (as spent, including PST and contingency) are converted to a stream of depreciation and financing charges.[35] Income taxes are added on top of financing charges. Depreciation charges are based on straight-line

Table 27: Property Taxes, Select Years

	2020 [$000S]	2025 [$000S]	2030 [$000S]
Land Assessed Value	10,230	11,295	12,470
Building Assessed Value	18,968	18,039	17,155
Interconnection Assessed Value	19,257	18,314	17,416
Total Assessed Value	48,456	47,647	47,041
Mill Rate (per Thousand $)	$50.51	$55.77	$61.57
Total Property Taxes	2,377	2,572	2,792
City Portion	1,582	1,711	1,858

Table 28: Total Capital Costs for Depreciation and Financing Calculations

	2020 [$000S]	NOTE
Building*	16,442	
Plant	56,730	Includes mechanical equipment and installation, excluding PST and contingency
Interconnection	22,073	Already includes contingency
Additional Contingency	14,634	Additional 20% contingency for building and plant (contingency for interconnection included in base budget)
PST	3,846	Assumes 50% of capital costs are subject to PST
IDC	7,676	Assumes weighted average construction financing period of 18 months, 4.5% debt rate
Total	121,400	

* Reflects only the portion of the total building costs allocated to energy production.

35 For the purposes of this study, ongoing maintenance costs are expensed (a conservative assumption).

Table 29: Annual Depreciation Charges

	TOTAL CAPITAL COST IN 2020 [$000s]	DEPRECIATION TERM	ANNUAL DEPRECIATION IN 2020 [$000s]
Building	21,799*	40 years	524
Plant	75,215	35 years	2,061
Interconnection	24,387	50 years	563
Total	121,401		3,147

** Reflects only the portion of the total building costs allocated to energy production. Total building cost including the rooftop farm is about $34 million.*

Table 30: Mid-Year Rate Base for Calculation of Financing Charges [$000s unless noted], Select Years

	2020	2021	2025	2030
Plant in Service	121,402	121,402	121,402	121,402
Accumulated Depreciation	(3,147)	(6,295)	(18,885)	(34,622)
December 31 Rate Base	118,254	115,107	102,517	86,780
Mid-Year Rate Base	59,127	116,681	104,091	88,354

depreciation and expected life for each type of infrastructure (Table 29). Depreciation rates are consistent with those for other comparable regulated assets in B.C.. Depreciation periods extend beyond the financial analysis for this study. However, there is less than $5 million in undepreciated rate base by the end of the selected analysis period (30 years).

Financing charges are calculated on the forecast of mid-year rate base (Table 30). Rate base reflects plant in service less accumulated depreciation. Financing charges are based on Creative Energy's projected WACC, which reflects a regulated capital structure, allowed after-tax ROE, and projected long-term debt rate (Table 31). The WACC reflects current capital structure and allowed after-tax ROE. The debt rate includes an allowance for some increase in interest rates by 2020. The forecast of financing charges is provided in Table 32.

An additional allowance for annual income taxes is added in the model. This allowance is calculated on a cash tax basis. Income tax calculations reflect a pre-tax ROE, an allowance for interest deductions, and existing accelerated capital cost allowances. The model assumes that all plant equipment and interconnection costs are eligible for Class 43 (30%), and the building is eligible for Class 1 (4%). If the building is also eligible for Class 43 or another CCA class with a higher rate, this would slightly reduce the project's present value income tax liability. Under the base case assumptions, the Fuel Switch would have no significant income tax liability until 2036. Thereafter, income taxes would average $1.2 million per year.

Table 33 shows the present value and levelized cost of depreciation, financing, and income taxes in the model. Together, these represent about one third of the total project cost of service.

Table 31: Creative Energy Weighted Average Cost of Capital

Debt Rate	4.5%
Debt Share of Capital Structure	57.5%
Return on Equity	9.5%*
Equity Share of Capital Structure	42.5%
Weighted Average Cost of Capital	6.63%
Discount Rate	5.95%**

** Reflects after-tax allowed ROE since income taxes are added separately.*
*** After-tax WACC including allowance for interest expense deductions. The after-tax WACC is used for all present value, levelized costs and levelized rate calculations in the report.*

Table 32: Forecast of Financing Charges [$000s unless noted]

	2020	2021	2022	2023	2024	2030
Mid-Year Ratebase	59,127	116,681	113,533	110,386	107,238	88,354
Debt	33,998	67,091	65,282	63,472	61,662	50,803
Equity	25,129	49,589	48,252	46,914	45,576	37,550
Interest	1,530	3,019	2,938	2,856	2,775	2,286
Return on Equity	2,387	4,711	4,584	4,457	4,330	3,567

Table 33: Summary of Depreciation, Financing and Income Taxes (30 years)

	PV [$000s]	LEVELIZED PER MWh*
Depreciation	43,500	$8.45
Interest	29,700	$5.77
ROE	46,400	$9.01
Income Tax	4,700	$0.91
Total	124,300	$24.14

** Delivered to Beatty Street plant.*

Table 34: Total Cost of Service [$000s unless noted], Select Years

	2020	2021	2025	2030
Fuel	6,848	6,995	7,897	9,489
Non-Fuel O&M	4,322	4,396	4,706	5,269
Property Taxes	2,377	2,414	2,575	2,792
Depreciation	3,147	3,147	3,147	3,147
Interest	1,530	3,019	2,693	2,286
Return on Equity	2,387	4,711	4,203	3,567
Income Tax	-	-	-	-
Total Cost of Service	20,612	24,682	25,217	26,551
Cost of Service $ per MWh*	$59	$71	$70	$68

** Per MWh delivered to the steam distribution system header at Beatty Street, including losses in the interconnection to the new Fuel Switch plant.*

8.1.6 Total Base Case Cost of Service

Table 34 shows the total base case cost of service for select years. Table 35 shows the present value and levelized cost of service over the entire analysis period from 2020 – 2049. Under base case assumptions, the levelized cost of service for the Fuel Switch over this period is $71 per MWh.

Table 35: Levelized Cost of Service, 2020 – 2049.

PV Costs [$000s]	$366,826
PV Energy Delivered to Beatty Street [MWh]	5,151,096
Levelized Cost	$71 per MWh

8.2 BASE CASE OF AVOIDED COSTS FOR GAS-FIRED STEAM

The first point of reference for the Fuel Switch project is the avoided cost of gas-fired steam from Creative Energy's existing steam plant. This capital cost of the existing plant is sunk and the plant will continue to be required for ongoing peaking and back-up even after the Fuel Switch. Furthermore, existing customers currently have no formal mandate or incentive for low-carbon energy (beyond voluntary commitments or additional offsets costs in the case of PSOs). Because new customers are expected to have formal carbon performance requirements, the following analysis focuses only on the avoided costs of gas-fired steam for existing (core) steam customers.

The primary avoided cost for the Fuel Switch is the natural gas (including carbon taxes) that would be displaced by the Fuel Switch.[36] The annual average efficiency of the existing steam plant is about 85%. However, the Fuel Switch is intended to supply baseload energy. Since the existing plant is more efficient in baseload conditions than in peak conditions, a slightly higher baseload efficiency of 86% is assumed for the purposes of calculating avoided gas use from the Fuel Switch. Under base case assumptions, the Fuel Switch would avoid about 376,000 MWh of natural gas use for core steam customers in 2020 (about 77% of current gas use).[37]

The avoided cost of natural gas for core customers is forecast for the full analysis period using third party forecasts of the natural gas commodity price, expected delivery charges, and current carbon taxes. This analysis ignores additional offset costs paid directly by PSOs for gas-fired steam. Creative Energy cannot capture the value of avoided offsets unless these customers pay some premium for low-carbon steam in lieu. The possibility of incremental revenues from existing customers is discussed further in the section on enabling strategies.

8.2.1 Natural Gas Commodity Forecast

Natural gas is among the most volatile commodities in the world, responding to complex interactions of drilling activity, wellhead production costs and production levels, weather, economic cycles, pipeline capacity, and levels of storage.[38] Gas commodity prices are not regulated. They are determined by North America-wide, and increasingly global-scale, market forces.

Creative Energy, like other utilities, does not take significant risk on natural gas costs. These are a flow through to consumers via the fuel cost recovery in Creative Energy's current rates. Forecasting natural gas prices is challenging. However, a forecast is required to estimate the costs/benefits the Fuel Switch and represent the baseline financial risks before other enabling strategies. For the base case analysis, a publicly available forecast of natural gas prices for Sumas (the closest pricing hub) from Sproule was used. The bulk of the analysis for this feasibility study was conducted using the Sproule forecast as of June 30, 2015. This is the forecast reflected in this section. However, the analysis of the financial gap in later sections of this report has been updated to reflect a more recent Sproule forecast from October, 2016. Sproule is a widely used forecast, often very similar to other publicly available and proprietary forecasts. Near-term prices are based on market forwards and longer-term prices are estimated based on fundamentals. As shown in Figure 26, gas prices remain depressed relative to historical values (in nominal terms), but are projected to recover somewhat by 2020 and beyond. Alternative gas price forecast scenarios, and their impacts on this project, are discussed in the sensitivity analysis for the financial gap.

8.2.2 FortisBC Delivery Charges

Natural gas delivery costs vary depending upon the location, size and type of consumer. Delivery rates are less volatile, as they are driven by largely fixed infrastructure. In contrast to commodity costs, delivery rates are regulated by the BCUC, which considers prudency of capital and operating costs, as well as an acceptable rate of return of natural gas delivery infrastructure. Larger customers tend to have lower delivery rates.

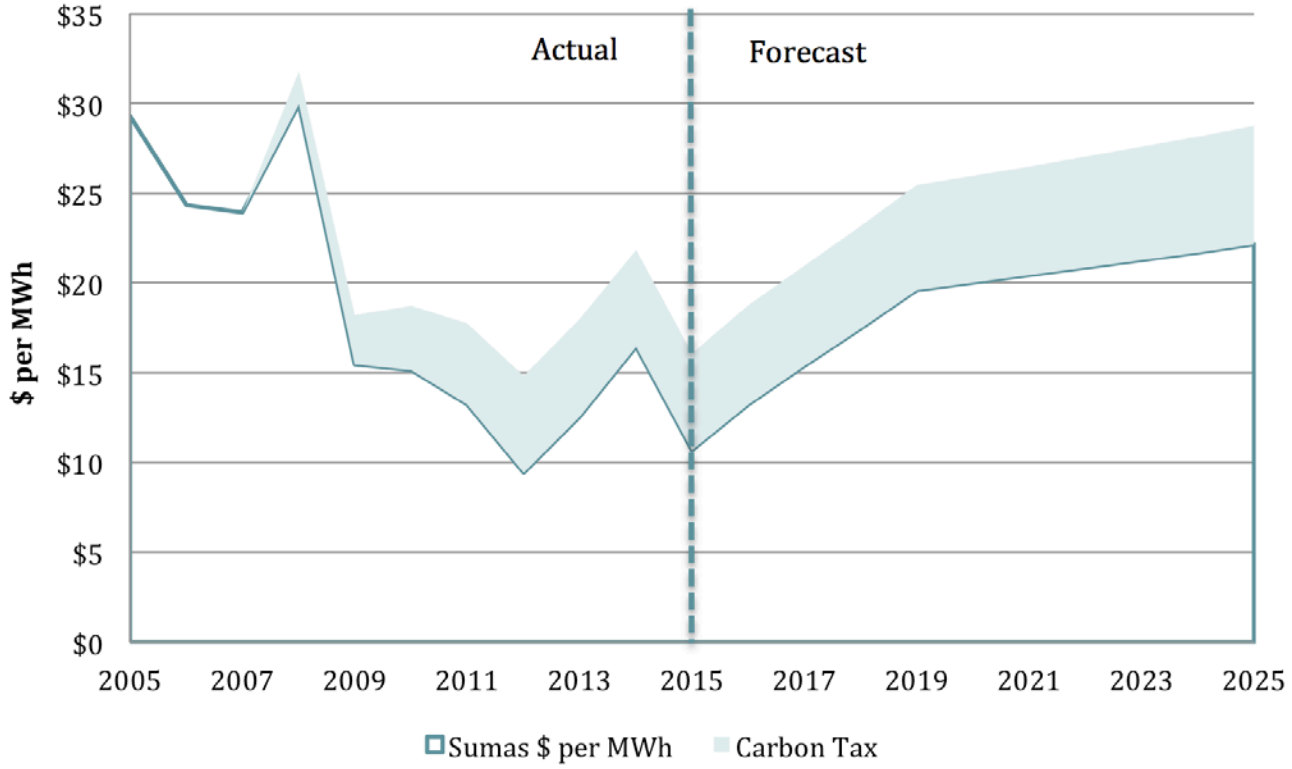
Creative Energy's existing Beatty Street plant purchases gas from FortisBC under Rate 22. This rate is for large volume customers purchasing

36 Consumables such as water and chemicals for water treatment are excluded from the analysis of avoided costs because these are also excluded from the Fuel Switch. The analysis assumes these are equivalent in both status quo and the Fuel Switch scenario. Labour costs are also excluded. The existing plant will need to continue to be staffed. Potential synergies between the existing plant and the Fuel Switch plant are already reflected in the incremental labour assumptions for the new plant. Further synergies may be possible. These are considered in optimizations. Given age, condition and ongoing use of existing plant, there are also no significant avoided capital costs assumed in the base case. However, some incremental capital or maintenance cost savings for the current plant may be identified with further due diligence and during detailed design of the Fuel Switch (e.g., use of dual fuel boilers).

37 Further due diligence will be required to confirm the operating strategy for the existing plant. As a peaking and back-up plant, there will still be a need to have boilers in the existing plant on hot standby even when they are not producing steam for customer use. This may require some additional use of natural gas in stand-by mode. This has not been factored into the analysis.

38 The underlying volatility in wholesale natural gas prices is often masked within retail prices through the use of deferral accounts (stabilization mechanisms) and less frequent adjustments in the retail rate. But in the end the consumer still pays for the actual underlying prices, even with lags and smoothing.

Figure 26: Nominal Sumas Gas Prices plus Carbon Tax, Historical and Projected



non-firm gas. While the delivery charges are substantially lower than other rate schedules, it allows FortisBC to curtail service with minimal warning, requiring use of backup fuel oil. Historically, service interruptions have been very rare, and when interruptions have occurred they have been at most a few hours, and have had minimal impact on overall fuel costs for the year.

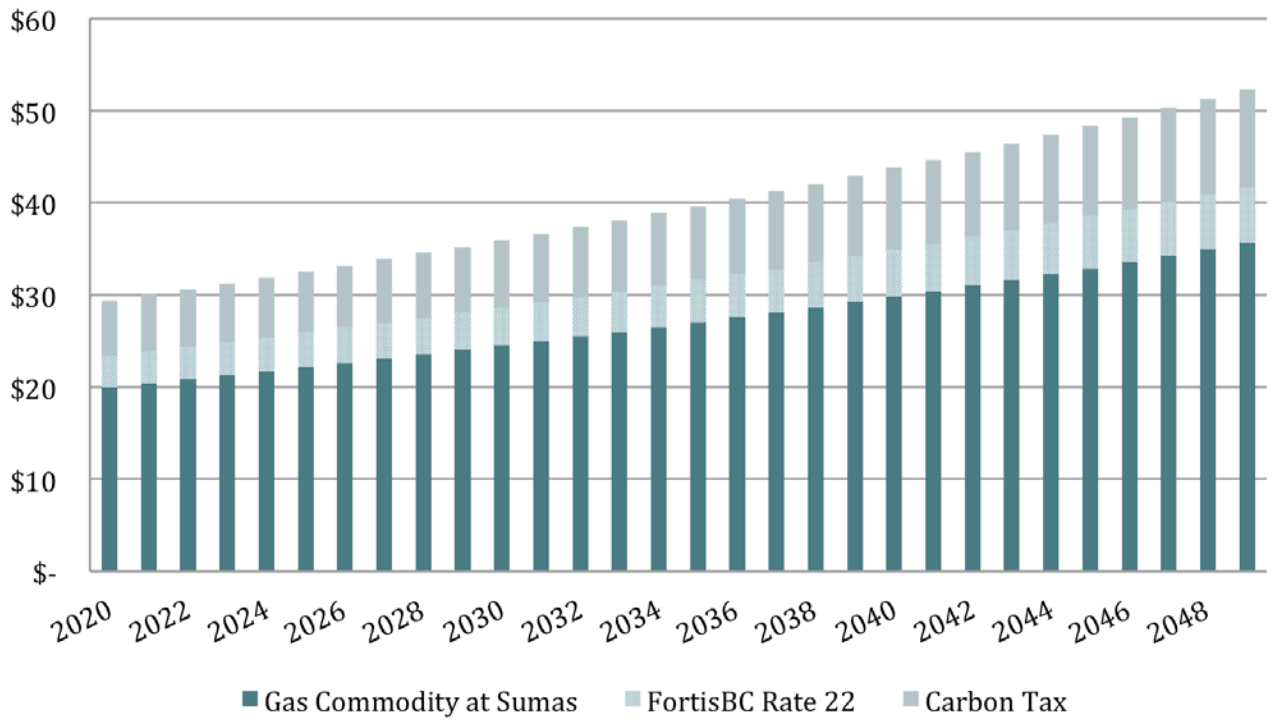
Rate 22 is currently $0.83 per GJ (including all riders), plus a monthly fixed charge. Creative Energy would not avoid the monthly fixed charge, as the Beatty Street plant would still be needed for full peaking and backup service, so only a variable charge of $0.83 per GJ is included in the calculation of avoided cost. FortisBC does not provide a forecast of future rate changes. The base case assumes these rates escalate at the rate of inflation.

Rate 22 does include a minimum charge based on 12,000 GJ of consumption per month. During summer months and some of the shoulder months, the Fuel Switch plant would provide all or nearly all the steam required by Creative Energy, so consumption at the existing Beatty Street plant could fall below 12,000 GJ for the month. The possible effect of this minimum charge has not been factored into the feasibility study. The impact could be on the order of $50,000 per year, which is well within the margin of error for the outputs in this study.

8.2.3 Carbon Taxes

British Columbia has a carbon tax. The 2015 carbon tax level is $30 per tonne of CO_2 equivalent, or $5.40 per MWh of fuel. Future carbon policies and prices are uncertain. The base case assumes the carbon tax remains flat in real terms, i.e. escalates at inflation. This represents a modest increase in the tax over time. In reality there are currently no commitments to raise the carbon tax in B.C.. However, studies show that B.C. will not meet its GHG reduction targets at current tax levels. There are also calls for higher

Figure 27: *Base Case Unit Cost of Gas Commodity, Delivery and Carbon Taxes ($/MWh)**



** Based on Sproule gas price forecast from June 2015.*

carbon taxes (e.g., from the Province's Climate Leadership Team). And there is a possibility of national actions. For example, in October 2016 the federal government proposed a national minimum floor on carbon prices (taxes or cap and trade mechanisms) of $50 / tonne by 2022. The federal government also acknowledged this was just a first step in actions that would be required to meet national reduction targets.

8.2.4 Forecast of Total Avoided Costs for Gas-Fired Steam

Figure 27 shows the forecast cost of gas (including commodity, delivery and carbon taxes) from June 2015. Table 36 shows the forecast avoided cost of gas per unit of steam sales for select years. Base on the forecast of June 2015, the levelized cost of gas-fired steam over the entire analysis period was $44 / MWh. This forecast was used in the initial feasibility analysis completed in December 2016. The gap analysis in later sections shows the effect of more updated assumptions.

Table 36: *Avoided Cost of Gas-Fired Steam for Existing Customers**

	2020	2030
Gas Cost $ per MWh	20	24
Delivery Charge $ per MWh	3	4
Carbon Tax $ per MWh	6	7
Total Gas Cost $ per MWh	29	36
Avoided Gas Consumption for Core Customers [MWh]	376,079	376,972
Avoided Gas Costs for Core Customers [$000s]	$11,013	$13,485
Avoided Cost for Core Customers [$/MWh Sales]	34	42

**Based on Sproule gas price forecast from June 2015.*

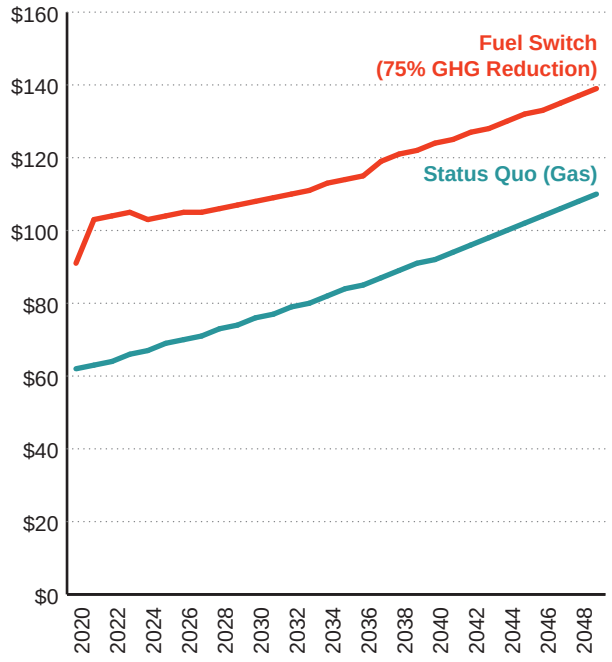
8.3 BASE CASE RATE IMPACT AND FINANCIAL GAP

For new customers, the Fuel Switch is a cost-effective means of meeting formal carbon performance requirements, even before further project optimizations. The financial model assumes all customers in NEFC and South Downtown would be secured through new franchise agreements, and that these customers in turn would pay the full cost of service for any energy they consume from the Fuel Switch.[39]

For existing customers, the cost of service for the Fuel Switch exceeds the forecast of avoided gas-fired steam under base case assumptions in the preceding section. Figure 28 shows the theoretical rate impact of the Fuel Switch under these assumptions without any further project optimizations or enabling strategies (discussed in later sections of the report). Under base case assumptions, the levelized rate increase for existing customers to achieve an immediate and permanent 75% reduction in GHG emissions would be about 43%. As noted previously, Creative Energy does not have long term contracts with the majority of existing customers. Although some customers appear to be willing to pay a premium for green energy under current policies, this would need to be confirmed through a formal subscription process culminating in new long-term contracts. In the absence of formal standards for existing buildings, it is unlikely all existing customers would be willing to pay that level of premium. The rate impact could be reduced by lowering the GHG reductions allocated to existing customers (this will require other customers for those reductions) and/or various optimizations and enabling strategies discussed later in this report.

Figure 29 shows the analysis from a different perspective. This chart shows the present value of the financial gap for existing customers assuming no rate increase. Essentially the output of the Fuel Switch for existing customers is valued at the avoided cost of gas-fired steam for these customers. The chart shows the gap under the gas price forecast from June 2015 and a more recent natural gas price forecast from October 2016. The chart also shows the effect of a recent

Figure 28: *Base Case Rate Impact of Fuel Switch for Existing Customers**



LEVELIZED RATES (BASE CASE ASSUMPTIONS)

Status Quo (Gas):
$77 / MWh

Fuel Switch (75% GHG Reduction for Core):
$110 / MWh

43% levelized rate impact before optimizations, alternate allocations or enabling tools.

** Rate impact under base case assumptions for gas and carbon prices; base case assumptions for allocation of project output (i.e., maximum and immediate allocation of GHG reductions to existing customer emissions); and before any further project optimizations or enabling strategies.*

39 As a result of the NEFC Decisions, there is now some uncertainty over future connections within NEFC and South Downtown. All things being equal, the NEFC Decisions increase the investment risk for the project relative to the gap analysis presented in this report. The City is reviewing other enabling strategies to secure customers. In the absence of such strategies, this risk could be managed by deferring or phasing the Fuel Switch. Deferring the Fuel Switch creates other types of risk (site and fuel availability, loss of potential project optimizations, higher interest rates, etc.). Deferral of the Fuel Switch project may also be counterproductive if potential customers for the project are required to implement other (smaller) projects to meet demands or requirements for low-carbon energy before the Fuel Switch goes in service . As shown elsewhere, there are limited phasing opportunities for the larger Fuel Switch, and phasing could also increase the financial gap for existing customers through a reduction in economies of scale.

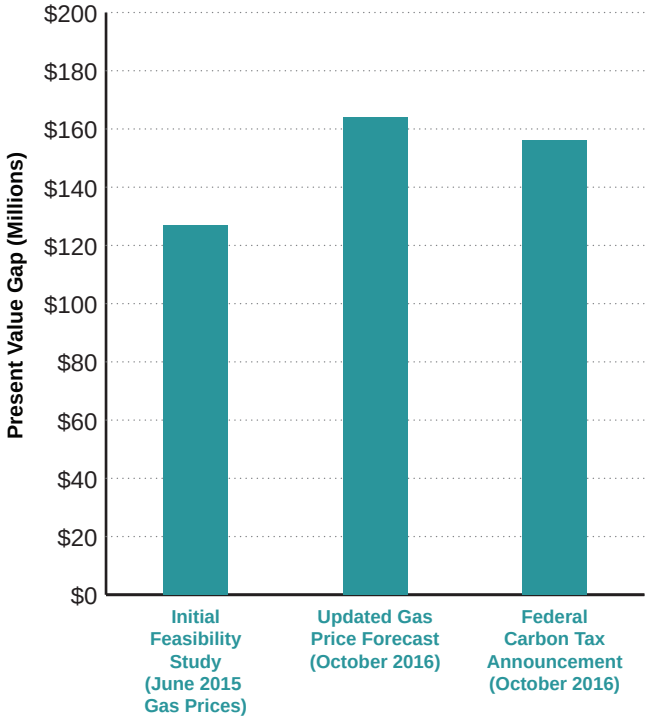
federal government proposal to establish a higher minimum floor of $50 / tonne on carbon prices by 2022 (versus B.C.'s current carbon tax of $30 / tonne). The projected financial gap under the gas price forecast from June 2015 was about $127 million. Using a more recent forecast from October 2016 (which is near record lows), the avoided cost of gas-fired steam has declined from $42 / MWh to $35 / MWh. All things being equal, this increases the forecast financial gap to $164 million. If implemented, the minimum floor on carbon prices proposed by the federal government in October 2016 would reduce the gap to $156 million.

The financial gap does not alter the fact that the Fuel Switch represents one of the largest and least-cost sources of GHG emission reductions. The financial gap represents the outstanding investment risk arising from a record low gas and carbon price outlook and a lack of formal carbon performance requirements for existing buildings. This investment risk will need to be addressed through some combination of project optimizations, alternative allocations of GHG emission reductions from the project (e.g., increased allocation to new developments and/or sale of external offsets), new long-term contracts with existing customers (via a subscription process which would ideally be supported by greater clarity on future GHG standards for existing buildings), grants, and other City enabling tools. These are discussed in Section 9 of this report.

8.4 SENSITIVITY ANALYSIS ON BASE CASE FINANCIAL GAP

The financial gap in the preceding section reflects base case assumptions. Given the current level of design and lead time for the project. there is still some uncertainty in many of these input assumptions. Some of these uncertainties (e.g., capital costs) can be resolved prior to construction of the project. Some represent ongoing market uncertainties (e.g., natural gas and carbon prices) that will need to be managed through contracting or other enabling tools. Table 37 describes key

Figure 29: *Base Case Present Value of Financial Gap for Existing Customers*



uncertainties in the base case analysis. Table 38 summarizes the range of assumptions used for sensitivity analysis. Figure 30 shows the results of the sensitivity analyses in the form of a tornado diagram which ranks the relative impact of each uncertainty on the financial gap. Figure 31 is a similar tornado diagram showing the relative impact of each uncertainty on the levelized cost of energy from the Fuel Switch.

By far the largest uncertainty affecting the base case financial gap is future gas and carbon prices. Natural gas is among the most volatile commodities in the world. The base case analysis uses a commodity price forecast from Sproule. Sproule prepares forecasts for specific gas trading hubs, which are updated periodically to reflect changes in near-term futures contracts and long-term expectations.[40] For example, the latest Sproule forecast for the relevant trading hub from October 2016 is lower than the one from June 2015 (Figure 32) and is also near historic lows. There is currently far more upside potential (price

40 The Sproule forecast reflects expected annual average prices. Annual averages depict broad trends and are adequate for an analysis of the expected gap, but these mask the large day-to-day and seasonal volatility in actual natural gas prices.

increases) than downside potential in natural gas prices. Upward pressure on natural gas prices could come from a combination of:

- environmental and economic pressure on production (particularly unconventional gas extraction);
- demand response (substitution of natural gas for coal, increased demand by industry, and adoption of natural gas vehicles as a result of sustained low prices and carbon policy in the transportation sector);
- substantial expansion of liquefied natural gas (LNG) export facilities to take advantage of the large price differential between North America and Asia.

A number of agencies prepare alternate forecasts based on scenario analysis of market fundamentals. The project team consulted a variety of alternate forecasts and decided to use scenarios prepared by the U.S. Northwest Power Planning Council (NWPPC) for long-term electric resource planning to depict a potential upper bookend for natural gas prices.[41] Figure 32 shows NWPPC's mid and high forecasts prepared for their most recent power plan. These forecasts were developed in US dollars and converted to Canadian dollars using the exchange rate at the time of publication in 2014. However, the Canadian dollar has since weakened considerably, which would result in higher prices, all things being equal. For the purposes of the sensitivity analysis in Figure 30, the mid forecast was used for the upper bookend, which considerably below the high scenario.

Carbon prices are less volatile year-to-year, but are a function of uncertain public policy. Existing prices are nowhere near the marginal abatement costs from various studies to achieve stated federal and provincial reduction targets. The team consulted a wide range of carbon price forecasts, including studies of the marginal abatement costs to meet reduction targets. In the end, the team selected a complete phase out of carbon tax as the lower bookend of uncertainty, and the proposal from the Province of British Columbia's Climate Leadership Team (CLT) for the upper bookend (Figure 33). The CLT proposed adding $10/tonne to the carbon tax every year, indefinitely, beginning in 2018. However, the level of tax under this proposal is still below the marginal abatement cost required to meet reduction targets in 2030 and 2050. The carbon price scenarios in Figure 30 are depicted in terms of their impact on the price of natural gas (reflecting the current carbon intensity of natural gas, based on burner tip emissions only). For example, the current carbon tax of $30/tonne translates to a premium of $5.50/MWh of natural gas.[42]

There is also uncertainty in the GHG intensity of natural gas. The current carbon tax on natural gas in B.C. and the GHG benefits of the Fuel Switch are calculated using the burner-tip GHG emissions for natural gas. This does not account for any upstream emissions associated with drilling, extracting, cleaning and transporting natural gas, nor does it account for the global warming impact from methane leakages. Taking these into account in the emission factor for natural gas could increase the carbon liability for gas-fired generation and also benefits of the Fuel Switch, even in the absence of any change in the level of carbon tax. In fact, one of the overlooked recommendations of B.C.'s Climate Leadership Team was that upstream emissions should be included in the carbon intensity used to calculate the carbon tax on natural gas. Even if this recommendation is never implemented, these upstream emissions should be considered in the benefits of projects such as the Fuel Switch.

There is some uncertainty around the magnitude of upstream emissions for natural gas. Recent

41 These scenarios were prepared by the NWPPC in 2014 as part of a regular planning exercise and are available at http://www.nwcouncil.org/energy/forecast/. Other forecasts consulted by the study team include ones prepared by BC Hydro (for its long-term resource plan), the U.S. Energy Information Administration (EIA), and the National Energy Board (NEB). The NWPPC mid forecast was selected as a conservative upper boundary for sensitivity analysis.

42 Carbon prices can also reflect other policies besides taxes. For example, the federal government has proposed a low-carbon fuel standard for home heating fuels. A 15% low-carbon fuel standard applied to natural gas would increase the levelized gas and carbon price in the base case analysis by 24%, assuming the standard is met with RNG at a marginal production cost of $14 / GJ. This would also require a substantial increase in RNG supplies, which represent less than 0.1% of current natural gas sales in B.C..

▲ *Rendering: interior of the Green House*

research suggests that the GHG intensity of unconventional natural gas (which makes up 80% of production in B.C.) could be as high as 380 kg / GJ, or over seven times the current GHG emission factor for natural gas in B.C. based on burner-tip emissions only. For the purposes of sensitivity analysis, a lower bookend for the gap was estimated that assumes a GHG intensity for natural gas of 240 kg / GJ, which is based on a recent mid-point estimate for conventional and unconventional natural gas. and assumes an 80/20 blend of conventional and unconventional gas. This sensitivity analysis also includes a non-zero GHG intensity for biomass in provincial accounting protocols to reflect direct emissions of NH_4 and N_2O (which may not be appropriate for true wood waste that will require alternative disposal methods). Adding a nonzero emission factor for biomass is is dwarfed by the much higher burner-tip and upstream emissions for natural gas.

Figure 30, the levelized cost of energy tornado diagram, does not show the impact of future gas and carbon prices, as they do not impact the cost of energy from the Fuel Switch. The levelized cost of energy tornado diagram does include one additional variable – the annual output from the Fuel Switch plant – as this variable has a material impact on the cost of energy from the Fuel Switch. Due to fixed costs, higher output will reduce the unit cost of energy, and vice-versa. The impact of this on the financial gap will also depend on how this additional energy production is allocated (e.g., between existing and new customers). For the selected range of scenarios, the output level does not significantly impact the total financial gap for existing customers so this variable has been excluded from Figure 30 but is considered in Figure 31 which shows the impact on levelized energy costs for the Fuel Switch.

Figure 34 shows how the financial gap varies with a continuum of combined gas and carbon prices. The upper and lower bookends are the same as shown in the tornado diagram in Figure 30.

Table 37: Key Uncertainties in Base Case Financial Gap

VARIABLE	
Gas and carbon prices	Future gas and carbon prices are highly uncertain and have the largest single impact on the financial gap (before other optimizations and enabling tools). The base case analysis is based on forecasts from Sproule, which are near record lows. Alternate gas and carbon price scenarios from a variety of sources were considered to depict conservative bookends for gas and carbon prices.
GHG Intensity of fuels	The GHG intensity of natural gas may be significantly higher than the base case assumption of 50 kg / GJ, which is based only on burner-tip emissions. A higher GHG intensity for natural gas would increase the carbon tax liability for gas-fired energy, even without any change in the level of the carbon tax. This would reduce the gap. At the same time, the GHG intensity of urban wood waste may not be zero if generic GHG intensity for all biomass sources is used from the best practice for public sector organizations (which takes into account direct emissions of NH_4 and N_2O for calculating the offset liability of public sector organizations).
Capital costs (base configuration)	Even before further design changes and optimizations (discussed in Section 9), there is uncertainty in final capital costs given the current level of design and procurement, as well as uncertain timing of development. While the potential impact of capital cost uncertainty on the financial gap is not as large as for gas and carbon prices, it is still material. However, unlike gas and carbon price risk, which can vary throughout the life of the project, uncertainty in capital cost risk would be substantially reduced by the final design and tender stages, and largely eliminated following the construction phase, at which point ongoing capital charges would be fixed (but for uncertainty in sustaining capital over the life of the project). Capital costs could vary (higher or lower) from the technology RFI based on more detailed design and changes in materials prices, exchange rates, labour markets, or other factors between now and the final tender phase. The base case assumptions already include a contingency. For the purposes of the sensitivity analysis, the contingency has been reduced and increased to test the impact capital costs could have on the final gap.
Wood waste prices	It is expected that wood waste prices will be established through a portfolio of long-term contracts or other mechanisms. However, there is always some ongoing default risk, and initial contracts may not extend for the full term of the gap analysis. As shown in the fuel research, there is limited quantity risk for fuel. The issue is price. A conservative starting price and escalation was assumed in the base case analysis. The sensitivity analysis considers the impact of both higher and lower prices.
Incremental operators	Incremental operators for the new plant reflect the proposed technology and scale of the project, as well as synergies with existing plant operations. The final incremental operator requirements will also depend on consultations with the BC Safety Authority. A realistic but conservative assumption of incremental operators was selected for the base case analysis. Higher and lower assumptions were developed in consultation with technical advisors.
Financing costs	The base case analysis reflects Creative Energy's current capital structure, debt rates (with some allowance for increases in long-term interest rates to 2020/21) and current allowed ROE (risk premium). Long-term debt costs can be fixed at project commencement, but there is still some risk of higher interest rates given the long and uncertain lead time for the project. The ROE would vary over the life of the project based on underlying interest rates, and a higher or lower equity risk premium may be justified depending on the final structure of customer contracts and enabling tools for the project.

VARIABLE	
Plant efficiency	Plant efficiency can vary with final design, actual performance and fuel quality. A conservative assumption was used for base case efficiency, but higher or lower efficiency is possible. The extent to which efficiency risk is transferred to customers, funders or the utility is yet to be determined.
Land value	Land value drives the lease assumption (before other enabling strategies such as tying lease rates to gas and carbon prices, as discussed in Section 9). The preliminary land value for the target site was developed from information provided by the City and third party benchmarks. There is a possibility of higher land values given the delays in project development. There is also some uncertainty around the final space requirements for Phase 1. A lower land value is unlikely, so this is shown as a one-way sensitivity.
Plant utilization	All things being equal, higher or lower plant utilization will reduce or increase levelized cost of the Fuel Switch output Effectively a higher utilization rate allows fixed costs to be recovered over a larger output. However, if this additional output is allocated to existing customers it will not have a significant impact on the financial gap for these customers since the benchmark is still gas-fired energy. For this reason, the sensitivity analysis for plant utilization was limited to the impact on levelized costs for the project and not the financial gap. The base case utilization is based on a representative load duration curve and growth rate for new customers. There is uncertainty in the actual rate of new development and also the shape of the load duration curve could be affected by changes in customer behavior, customer mix or other factors such as use of steam for cooling in the summer months.

Table 38: *Range of Assumptions for Sensitivity Analysis*

VARIABLE			
Gas and carbon prices*	NWPPC Mid + CLT Carbon Tax Proposal	Sproule (October 2016) + Current Carbon Tax (Escalated at Inflation)	Sproule (October 2016) + Elimination of Carbon Tax
GHG intensity of fuels	Natural Gas: 864 kg / MWh Biomass: 8 kg / MWh	Natural Gas: 180 kg / MWh Biomass: 0 kg / MWh	Natural Gas: 180 kg / MWh Biomass: 8 kg / MWh
Capital costs (base configuration)	Table 28 Costs -20%	Table 28 (including taxes and contingencies)	Table 28 Costs +20%
Wood waste prices	-15% ($63 / BDT escalating at 2% / year)	$74 / BDT escalating at 2% / year	+15% ($85 / BDT escalating at 2% / year)
Incremental operators	7 FTEs	12 FTEs	15 FTEs
Financing costs	Debt 4%, ROE 9%	Debt 4.5%, ROE 9.5%	Debt 5.5%, ROE 10.5%
Plant efficiency	75.8%	80.8%	85.8%
Land value	No low bookend	$10 million	$15 million
Plant utilization	+10%	6,050 EFLH**	-20%

** Lower gas and carbon prices result in higher financial gap while higher gas and carbon prices result in lower financial gap.*
*** Equivalent full load hours*

Figure 30: *Tornado Diagram Depicting Impact of Uncertainties on Base Case Financial Gap for Existing Customers*

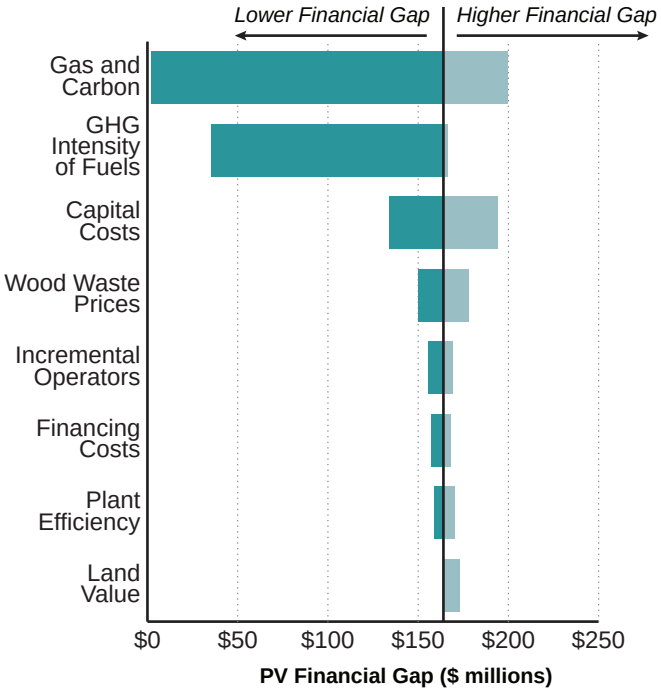


Figure 31: *Tornado Diagram Depicting Impact of Uncertainties on Levelized Cost of Energy from the Fuel Switch*

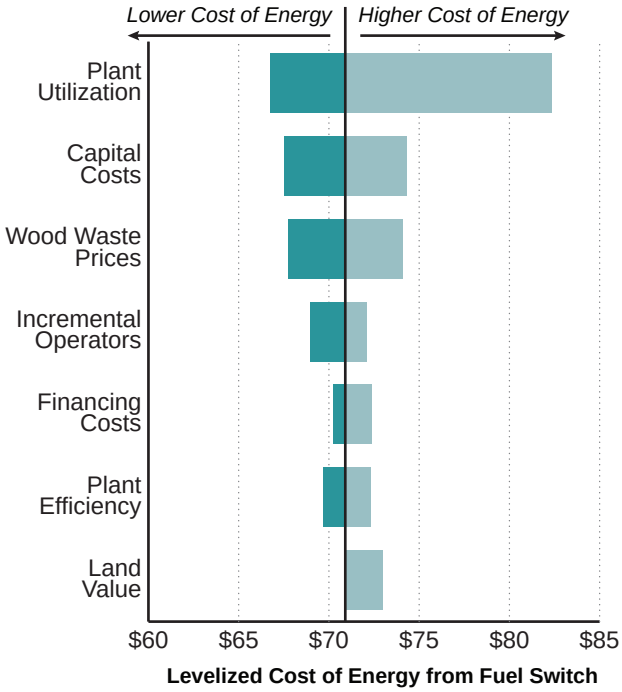


Figure 32: *Alternate Natural Gas Price Scenarios (Nominal $/MWh)*

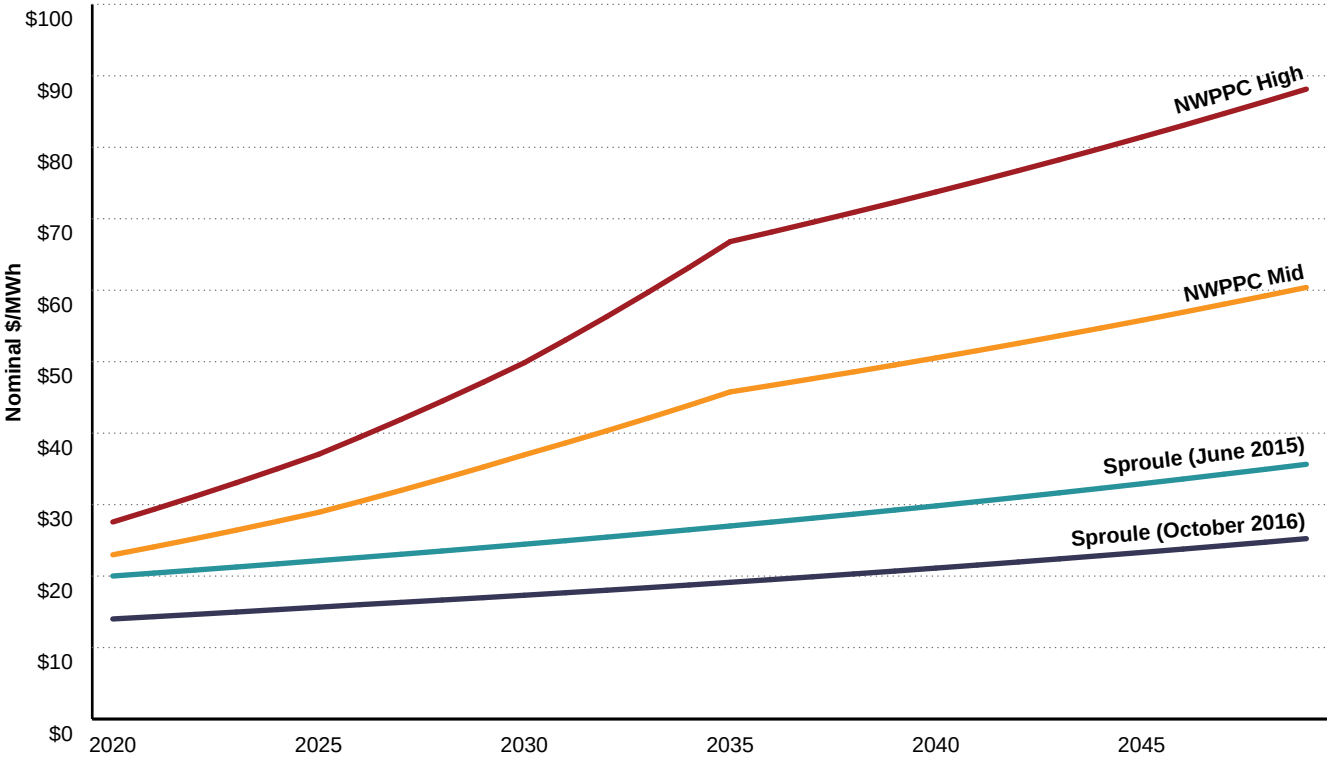


Figure 33: *Alternate Carbon Price Scenarios (Nominal $/MWh of Natural Gas)*

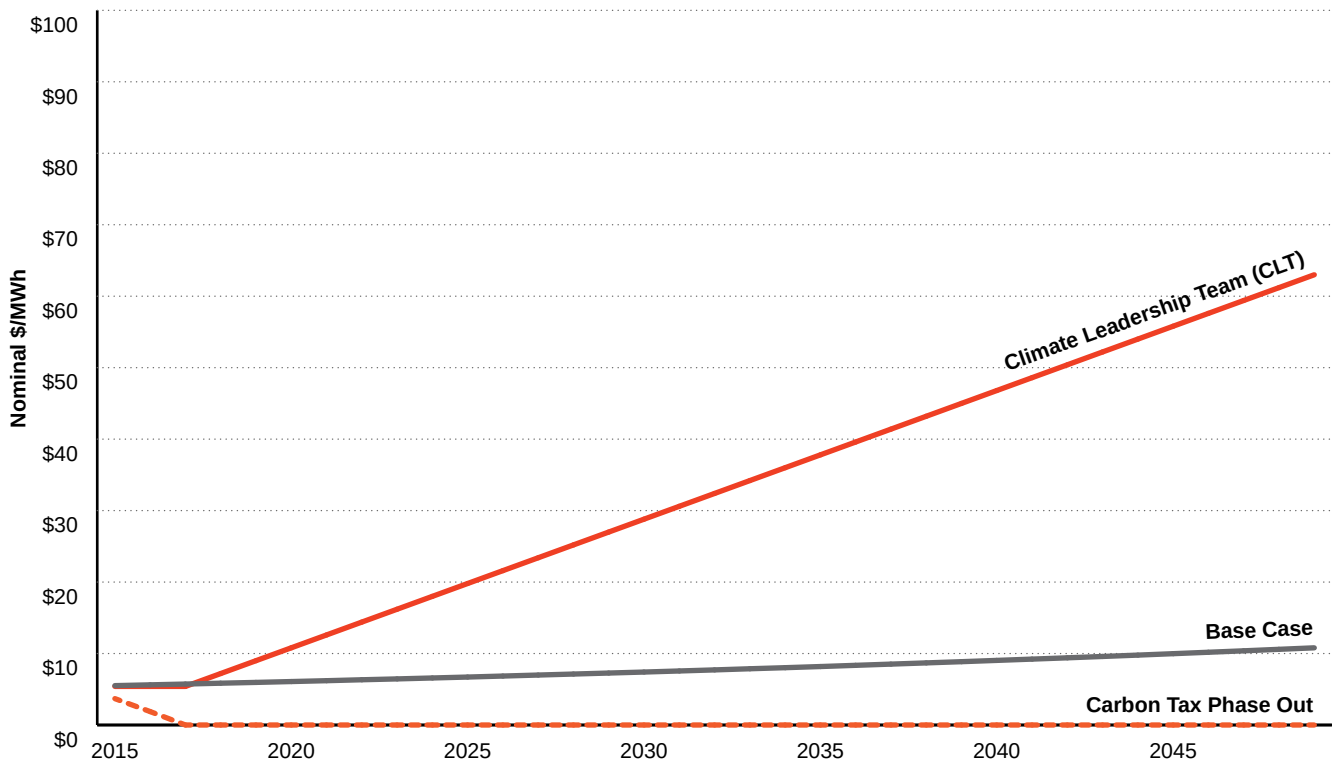
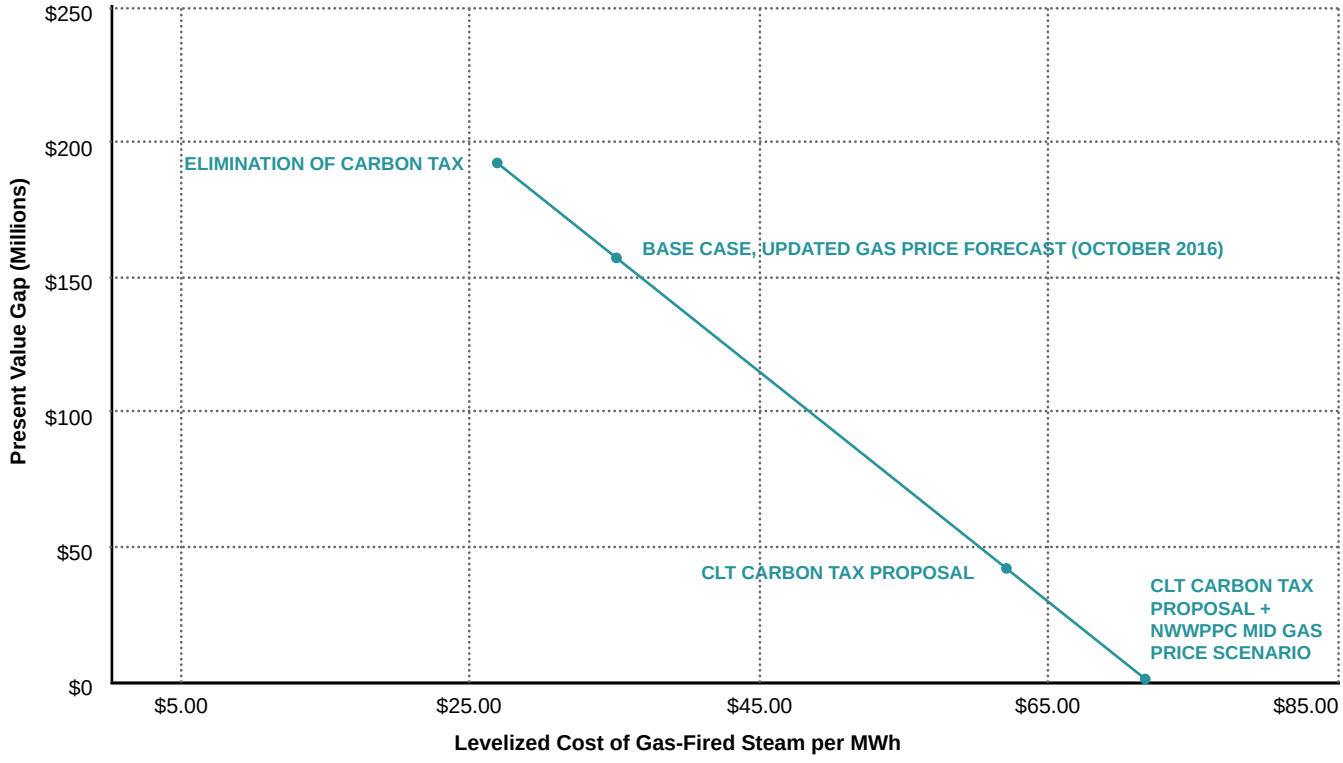


Figure 34: *Risk Profile for Financial Gap for Existing Customers (Base Case GHG Allocations) Under a Range of Gas and Carbon Price Projections Before Other Contracting Strategies and Enabling Tools**



** Reflects financial gap under a range of combined gas and carbon price scenarios, before any further project optimizations, enabling tools, alternate customer scenarios. or voluntary contracts. Range of price scenarios is not exhaustive. However, probability of scenarios lower than current base case are smaller given existing government policy and climate targets. CLT refers to the Climate Leadership Team which was established by the Province to advise on recent updates to the Climate Action Plan. The CLT proposed an escalation in the carbon tax of $10 per year indefinitely. NWPPC refers to the Northwest Power Planning Council, which regularly prepares scenarios of long-term natural gas prices to inform resource planning in the U.S. Pacific Northwest.*

8.5 GHG REDUCTIONS

For the purposes of estimating GHG reductions, the feasibility study assumes the project will displace gas-fired steam to supply both existing Creative Energy customers and new development (in the base case development in NEFC and South Downtown). Under the base case sizing and load assumptions, the output of the Fuel Switch would increase over time until full build out of the NEFC and South Downtown neighbourhoods around 2030.[43] At full build out of these neighbourhoods, total emission reductions would be approximately 81,000 tonnes per year under base case assumptions. This is equivalent to the GHG emission reductions from removing approximately 16,500 vehicles from the road. This is also equivalent to 11% of the GHG offsets purchased by the Province in 2014 under its carbon neutral government commitments, which include offsets purchased for direct government operations as well as public schools, universities and hospitals. The Fuel Switch (Phase 1) represents approximately two thirds of the GHG reductions that the City currently anticipates it will achieve from all neighbourhood energy systems, which is a conservative assumption of the potential for neighbourhood energy to deliver cost-effective GHG reductions and renewable energy.

There is some uncertainty around the total GHG savings associated with this project, as the base case calculations only reflect the burner-tip emissions from natural gas, and do not capture upstream emissions from production or transportation. Recent research suggests that these emissions may be far higher than originally understood. Based on recent research discussed in Section 2, the annual emission reductions could be on the order of 380,000 tonnes (using mid-point estimates for the total emissions for non-conventional and conventional gas, and assuming an 80/20 blend of non-conventional and conventional gas). Accounting for the emissions associated with wood waste combustion would reduce this by approximately 4,000 tonnes per year, to ~375,000 tonnes.[44]

The base case analysis assumes about 17% of emission reductions from the project will be allocated to new development by 2030. This allocation is sufficient to meet a target GHG intensity of 0.07 tonnes of carbon dioxide (or equivalent) per MWh of heat delivered in NEFC and South Downtown. This is the target emission intensity for the City's existing low-carbon Neighbourhood Energy Utility in SEFC. It is also the target that was proposed in the Neighbourhood Energy Agreement between the City and Creative Energy for NEFC. The City has recently proposed to reduce the GHG intensity for new construction over time. This has not been formalized but if this policy were implemented it would require some additional energy from the Fuel Switch to be allocated to new developments in NEFC and South Downtown then is assumed in the current base case. All things being equal, this would reduce (modestly) the GHG savings for existing customers, but also the residual financial gap associated with existing customers (assuming no upsizing of the Fuel Switch or addition of other sources of low-carbon energy). If the Province changes the GHG intensity applied to natural gas, then even higher amounts of low-carbon energy would need to be allocated to new developments to achieve the same target GHG intensity (due to the residual gas-fired energy having higher emissions).

Other allocations of GHG reductions from the project are also possible. First, more of the project capacity could be directly allocated to new customers connected to the network downtown. This could include infill development within the core, new development in new expansion areas (e.g., Westend, Georgia Corridor, Chintatown, and Downtown Eastside), and existing buildings downtown not connected to the system but served with gas-fired heat. As noted in the next sections, this would reduce the GHG emission

43 The utilization of the plant is limited by the load duration curve of the system. In early years of the project, there would be some excess capacity in the project to meet NEFC and South Downtown neighbourhoods are built out. other existing buildings can be connected to the project.

44 This reflects direct emissions of NH_4 and N_2O, which is required in the Province's best practices guide for public sector organizations when calculating offset liabilities. However, these emission factors are for all sources of biomass and it is not clear whether they should be applied to urban wood waste which would require alternative disposal methods. In any event, the impact on project benefits is minimal and the uncertainty around biomass emissions is dwarfed by the uncertainty in upstream natural gas emissions.

▲ *Rendering: interior of the Green House*

reductions attributable to existing customers but also the financial gap before other optimizations or enabling tools. There is also the possibility to supply additional low-carbon energy to the City's SEFC NEU. It would also be possible to displace gas-fired energy for existing customers downtown and transfer or sell the resulting GHG reductions to other low-carbon energy systems within the City or to third parties as offsets. This could include the sale of offsets required by the Province under its carbon neutral commitments. These alternate allocations could be used to phase in the substantial reductions allocated to existing customers in the base case analysis. Alternate allocations of the GHG reductions from the project are discussed in the next section. None of these alternate allocations alters the overarching GHG benefits of the project, merely how those benefits and costs are distributed.

9. OPTIMIZATIONS AND ENABLING STRATEGIES

This section considers potential optimizations and enabling strategies to address the financial gap and investment risk for the Fuel Switch project under the base case assumptions from the previous section. Many of these strategies will require support from the City. There are also possible roles for the Province and the federal government to show support by providing clarity on future carbon policies, providing grants, purchasing offsets, and/or purchasing low-carbon energy or credits from the Fuel Switch for provincial and federal buildings.

9.1 PROJECT OPTIMIZATIONS

9.1.1 Plant Location

The feasibility study was conducted assuming the new Fuel Switch plant would be sited on City-owned land along Industrial Avenue. The siting and interconnection study also identified two alternative locations for the Fuel Switch plant: 1) the proposed site of Providence Healthcare's new St. Paul's Hospital campus at Main and Prior streets; and 2) one of two adjacent fee-simple parcels within the Port Metro Vancouver lands along Burrard Inlet. The team had intended to consider these alternative sites in sensitivity analyses and potential optimizations. However, based on further due diligence and discussions with various stakeholders over the past year, these alternative sites are no longer considered viable.

While there could be additional synergies to co-siting a new steam plant with a new hospital, it now appears there will not be adequate space at the new campus to host the Fuel Switch plant or allow future expansion possibilities. However, the new St. Paul's Hospital campus still represents an important customer for the Fuel Switch project. The existing St. Paul's hospital has been a long-time customer of Creative Energy. The new site is located along the proposed interconnection between the Fuel Switch plant and the existing Beatty Street plant. The line could supply both heating and process steam needs of the new hospital, similar to the steam service at the existing hospital. As a Public Sector Organization, St. Paul's must also purchase additional offsets under B.C.'s carbon neutral government commitments. The new campus will also have to meet the City's carbon performance requirements for new development.

Connecting the new hospital campus to the expanded Creative Energy steam system could also provide additional security of supply and minimize capital requirements for on-site systems. Hospitals are required to have high levels of redundancy in their heating systems, and typically have on-site heating systems with multiple redundant units. Following the Fuel Switch, the Creative Energy steam network would be supplied by two separate plants with the ability to use three separate fuel sources to supply peak demands. Further, the new hospital campus could be supplied from two different directions on the line. These factors could help to minimize or even eliminate the need for the hospital to invest in redundant on-site boilers. In addition, any on-site boilers still required by the hospital to provide redundancy for critical needs could be leveraged to provide capacity / reliability for the larger steam network during normal operations. This could also provide the new hospital campus an opportunity to offset capital or operating costs associated with any on-site infrastructure required for redundancy.

The potential sites within the Port lands are not currently available. These sites are also further from the downtown network and the future of industrial steam loads within the Port lands is uncertain. The Port also does not consider energy production to be within its mandate.[45]

45 There could be a role for the Port in delivery and storage of wood waste for projects such as the Creative Energy Fuel Switch.

9.1.2 Interconnection Optimization

The interconnection cost of $24 million (2020$) in the base case analysis assumes a new buried steam line along the entire 2.4 km route from the Fuel Switch plant to the existing Beatty Street plant. The interconnection study identified several opportunities to reduce the interconnection cost. The two most significant and promising opportunities would be to bore underneath the railway tracks to reach Terminal Avenue, and to hang part of the interconnection from the existing SkyTrain infrastructure, which runs near significant portions of the proposed interconnection alignment. These optimizations are not mutually exclusive, and together they could reduce the cost of the interconnection by $12.4 million, or over half of the cost in the base case analysis. There would also be follow-on savings in maintenance costs (fewer manholes) and property taxes (assuming property taxes on the interconnection). There are precedents for both of these strategies, but they would require permission from TransLink and CN Rail. The City will need to play a role in securing these permissions.

9.1.3 Plant Sizing

There are considerable economies of scale for the Fuel Switch project. These reflect economies of scale in plant equipment and operations (staffing), but also fixed upfront costs for the interconnection, site and building. However, it may still be possible to phase equipment within the plant to reduce initial investment risks in the absence of sufficient contracts or other enabling tools. The feasibility and cost of phasing will depend in part upon the final technology selection and design.

To test the possible impacts of phasing, a screening analysis was completed assuming an initial installed capacity of 45 MW (vs. 65 MW). This scenario assumes one of three boilers are deferred. This aligns with the average number and size of individual boilers from shortlisted technology providers. An alternative sizing at 32 MW was also tested (assuming only two large boilers); however, the financial and environmental performance were much less favorable than for the 45 MW scenario.

For the 45 MW screening analysis, the total mechanical cost of the base plant was reduced by one third. This is an optimistic assumption because it may be difficult to phase some elements of the plant (e.g., fuel storage or emission controls), and there may be other cost impacts from phasing equipment. No change was made in interconnection costs, land costs, building costs or staffing requirements. The screening assumes the third unit is deferred indefinitely in order to analyze the impact on the base case gap.

Under these assumptions, the financial gap would decline from $164 million to $144 million, before any other optimizations, enabling tools or alternative contracting strategies. However, the unit cost of energy from the Fuel Switch would also go up approximately 11%. There would also be a smaller reduction in GHG emissions associated with a smaller plant - 62,000 tonnes vs. the base case of 81,000 tonnes per year. The implicit cost of carbon abatement for a smaller plant would increase about 17.5% relative to the base case. Assuming fixed allocations of GHG reductions to NEFC and South Downtown (reflecting formal carbon performance standards for new development in these neighbourhoods), the residual emission reductions that would be available to the core or other customers would decline by 28%.

9.1.4 Combined Heat & Power

Many of the precedent projects examined for this study produce both heat and power with CHP. In many jurisdictions, CHP can lower the cost of heating and also provide additional GHG savings. In B.C., however, CHP provides minimal incremental GHG benefits given the existing low GHG intensity of electricity.[46] Nonetheless, if the incremental value of electricity production exceeds the incremental costs, CHP could help reduce the cost of heat production and the expected financial gap for existing steam customers.

A range of potential CHP configurations was considered for this analysis. A single-extraction condensing turbine was considered the most economical approach given Creative Energy's steam requirement. Under this configuration,

46 This assumes no increase in GHG intensity and ignores any effects from trade on GHG intensity.

all boilers in the Fuel Switch plant would be configured to generate steam at a higher temperature (400 °C) and pressure (4,800 kPa) than normally required for steam service. The resulting steam would be passed through a condensing steam turbine. The turbine would have an extraction valve midway along the body of the turbine to remove the majority of the steam from the turbine at 1,500 kPa for use in Creative Energy's steam network. A small amount of steam would pass through the rest of the turbine and condense into hot water. The energy in this hot water could be used within the plant (e.g., pre-heat of make-up water) or for hot water networks such as the SEFC NEU. The condensing turbine could power a 6.9 MW electric generator and produce about 41,000 MWh of electricity annually. This represents the maximum electricity output under base case assumptions for steam demand. At this scale, the CHP project would be eligible for BC Hydro's current Standing Offer Program (SOP).[47]

CHP would add about $26 million to the base capital cost of the Fuel Switch project. This is the incremental cost of the turbine, generator, power interconnection, and higher pressure steam boilers. CHP would also increase the amount of urban wood waste required for the Fuel Switch project by about 18,000 BDT/year (about 18% increase relative to base case assumptions).[48] Under projected prices in BC Hydro's SOP, electricity production could add $2.6 to $3 million of net revenues annually to the Fuel Switch project (i.e., revenue from electricity sales less incremental O&M and fuel costs for CHP).[49] After also taking into account the additional upfront capital cost, CHP could reduce the financial gap of the Fuel Switch project by $4 – 7 million under base case assumptions and before other optimizations and enabling strategies. However, CHP would also increase project complexity, increase the required fuel supply, and introduce some new financial risks (since the price of urban wood waste can still vary while the price from BC Hydro's SOP would have a fixed escalation).

9.1.5 Dual Fuel Boilers

Biomass-fired boilers are an established technology that can achieve high levels of uptime. However, biomass-fired boilers do not have the same level of reliability as gas-fired boilers. They have more working parts and are more complex to operate.

The base case analysis assumes Creative Energy's existing gas-fired steam plant will provide full back-up of the Fuel Switch plant and interconnection. However, the use of one or more dual fuel boilers in the Fuel Switch plant could reduce the need for future capacity additions or replacements elsewhere in the system. Biomass boilers are often designed to use small amounts of natural gas for startup only. A dual fuel boiler is designed to run at full output (or close to it) using either natural gas or wood waste. This would give the boiler an alternative source of fuel and would slightly increase its overall reliability. A dual fuel unit may not provide as high a level of reliability and firm capacity as a gas-only boiler, but it would likely provide a higher level of reliability than a biomass-only boiler. A reasonable strategy for the Fuel Switch plant would be to design one of the modules (out of three total) as a dual fuel boiler. The capital cost impact is estimated to be on the order of $1-2 million.

The other strategy to provide additional firm capacity would be to install one or more gas-fired boilers at the Fuel Switch plant. This would give Creative Energy additional firm capacity at a separate location, increasing the system's overall reliability. In addition to the capital cost of the

47 The analysis of CHP is based on the current SOP. The Fuel Switch project would not be in service before 2020. BC Hydro recently advised all potential applicants to the SOP that it has received sufficient applications to fill the remaining available SOP energy volume for target commercial operation dates up to the end of calendar year 2019. BC Hydro has indicated that price and volume beyond 2019 are currently under review and both the price and volume may change post 2020.

48 An alternative configuration would be to increase the operating pressure of the steam boilers without changing boiler capacity. The addition of power generation would then reduce the steam available for the heating network. Under this configuration, CHP could be used to reduce the absolute gap in the absence of sufficient subscription sales or other enabling strategies for the target GHG reductions for the core.

49 Current standing offer price in Lower Mainland is approximately $110 / MWh but under current SOP rules this price would escalate at CPI until commercial operation date and then one half of CPI thereafter. Assuming a commercial operation date of 2020, the applicable starting price for electricity production would be about $120 / MWh.

▲ *Interior of 720 Beatty Street plant*

boilers, this may require additional building space depending on the size and number of boilers installed. We have not evaluated the cost impact of adding separate gas boiler capacity at the Fuel Switch plant. Given the significant excess capacity available in the interconnection line, there would be no impact on the cost of the interconnection.

9.1.6 Absorption Chilling

The Fuel Switch has high fixed capital costs. One of the ways to reduce the unit cost of service for the Fuel Switch is to increase the utilization of plant capacity during off-peak periods such as summer months. One of the most obvious opportunities to do this is through the use of Fuel Switch-generated steam in absorption chillers to provide cooling (on-site or centralized). Absorption chillers have higher capital costs and lower efficiency than electric chillers. However, in limited circumstances they can be more economic than electric chillers, particularly in jurisdictions with high summer power rates. Absorption chilling can also have significant environmental benefits when displacing electric power with high GHG intensity. These conditions are more common in other parts of North America. However, new absorption chilling applications are still uncommon in North America. The study team conducted a high-level analysis of absorption chilling in downtown. The most promising application would be for large commercial cooling loads. Even under optimistic assumptions for the summertime cost of steam (based on the variable cost of production from the Fuel Switch),[50] electric tariffs in B.C. (which do not vary by season or time of day), low incremental capital costs of absorption chillers, and best case assumptions for the efficiency of absorption chilling, the study team found minimal customer benefits from implementing absorption chilling using steam from the Fuel Switch. Based on this analysis, this option was not considered further. However, changes in technology or markets may provide opportunities for absorption chilling in the future, which could lower the cost of energy from the Fuel Switch and any residual gap to be covered by other enabling tools.

50 In order to provide some financial benefit to the Fuel Switch project, the summertime rates would need to be set at a level that creates some margin above the variable costs of production, so these assumptions are overly favorable to absorption chilling.

9.1.7 Other Revenue Sources

The City's Green Building Policy for Rezoning requires all new developments which have received rezonings to be certified LEED Gold or greater with a minimum 22% reduction in energy costs as compared to ASHRAE 90.1 2010. Connection to the Fuel Switch project can provide LEED points for developers, who would otherwise need to spend money to achieve LEED points elsewhere in their projects. The cost of Fuel Switch energy for new customers could be reduced through upfront developer contributions in aid of construction, which developers could be required to pay in recognition of the value they are receiving from LEED points produced by the Fuel Switch. However, there are currently no mechanisms in place to secure such contributions. Further, LEED does not currently recognize future projects such as the Fuel Switch which may not be complete until after a given LEED building has been built and received certification. As a result, it may be difficult to secure the benefits of the Fuel Switch for early adopters. This is also a potential barrier to securing near-term development for the Fuel Switch project, since developers could be required to implement other on-site measures with the same or higher costs to secure LEED certification. Those measures (which could include a mix of envelope and equipment efficiency as well as on-site energy sources) could in turn reduce demand for energy from the Fuel Switch, raising overall consumer costs. In any event, developer contributions in aid of construction would likely need to be used to buy down the cost of energy for customers in new developments. While important for reducing the cost of low-carbon energy for new development, developer contributions do not address the financial gap for existing customers, although securing new development does support economies of scale for all users, including existing buildings.

9.2 GRANTS

Government grants may be necessary to advance cost-effective but time-sensitive carbon reduction projects such as the Creative Energy Fuel Switch until the gap between government GHG reduction targets and carbon policies is addressed. Given the purpose of these grants is to bridge this gap, they could be structured to be recovered by government if gas and/or carbon prices increase.

Virtually every existing low-carbon district energy project in B.C. to date has received government grants. For example, SEFC received a $10 million grant from the Province, which is equivalent to about 50% of the cost of the SEFC Energy Centre. The UBC Bioenergy Research and Demonstration facility received federal and provincial grants offsetting virtually the full capital cost of the plant. And SFU has received a grant for the proposed biomass heating project under development for both UniverCity and SFU under the Province's Carbon Neutral Capital Program equivalent to about 25% of the capital cost for its share of the plant.

The Province does not currently have any specific grant programs in place that are applicable to the Creative Energy Fuel Switch.[51] For comparison, the Province recently announced a $40 million Clean Energy Vehicle Program which will provide incentives of $5,000 - $6,000 for between 5,000 and 6,500 electric vehicles. Given an average emission reduction of 5 tonnes per vehicle per year, this implies a subsidy of $85 - $100 / tonne of carbon reduction.[52] The Fuel Switch would eliminate a total of 81,000 tonnes of GHG emissions, which is equivalent to about 16,500 cars over 30+ years. However, the financial gap for the Fuel Switch is only associated with emissions for existing buildings, which represent about 67,500 tonnes under base case assumptions. Assuming the interconnection

51 The Province established the Community Energy Leadership Program (CELP) in 2015 to support local government and First Nations investments in energy efficiency and clean energy projects. The goals of the program are to reduce greenhouse gas emissions, increase energy efficiency, stimulate economic activity in the clean energy sector, and support vibrant and resilient communities. The program is funded through the Province's Innovative Clean Energy (ICE) Fund, which is a Special Account funded through a levy on certain energy sales. Round 3 of CELP funding has closed and there have been no announcements of future rounds. For this round a total allotment of $550,000 is available to fund projects. However, the CELP is oriented to small projects, and contributions will range from $25,000 to $175,000 per proponent.

52 Calculation assumes a vehicle life of 15 years and a 3% discount rate, consistent with federal Treasury Board guidance for discounting environmental benefits. This calculation does not consider the additional cost of the $6,000 incentive provided by BC Scrap-it Program when an older car is scrapped for a new electric vehicle. This incentive is also partially funded through federal and provincial grants.

optimization and excluding property taxes (which represent a government transfer) the net gap for existing buildings is approximately $118 million. The implied carbon cost of $118 million for 67,500 tonnes of emissions over 30 years is approximately $87 / tonne.[53] In the absence of grants, the Province can still support the Fuel Switch project through the purchase of carbon offsets (discussed below).

In its 2016 budget, the federal government announced investments of $11.9 billion in public transit, green infrastructure and social infrastructure. The federal government's Fall Economic Statement proposed an additional $81 billion through to 2028 in public transit, green and social infrastructure, transportation infrastructure that supports trade, and rural and northern communities. The federal government also announced it will establish a new Canada Infrastructure Bank, an arm's-length organization intended to increase investment in growth-oriented infrastructure. The federal government has also announced a $2 billion Low Carbon Economy Fund, which is expected to begin in 2017. This fund is intended to support concrete measures that generate new, incremental GHG reductions while considering cost-effectiveness. Taking all previous and recent announcements together, the federal government has committed more than $180 billion in infrastructure funding to 2028.

Unfortunately, the design of programs to allocate new federal funds have yet to be announced, including eligibility requirements, level of individual grants, structure of grants, and evaluation criteria. Regardless, the Fuel Switch project would appear to align very well with the general policy objectives for federal infrastructure funding, and the Low Carbon Economy Fund in particular. The Low Carbon Economy Fund is the most promising source of funding in terms of alignment and timing. However, the Province is likely to be a gatekeeper for any federal funds. And it is not yet clear whether the City would need to own specific assets in order to secure grants for the project.

As a regulated utility, any grants received by Creative Energy directly would reduce Creative Energy's net investment and rate base. Grants go directly to reducing customer rates (or in the case of existing customers they reduce the current gap between status quo and the cost of service for the Fuel Switch). The net effect would be the same if the grant was provided to the City to pay for specific assets owned by the City.

For the purposes of the enabling scenarios a $50 million grant has been considered. This was considered a realistic target for a project of this size and impact. This level of grant would make a substantial contribution to advancing the project for existing buildings, although additional enabling strategies would still be required. A larger grant may be available. Assuming 60,000 tonnes of residual reductions available for existing buildings (after additional sales to SEFC), the implied carbon price for a federal grant of $50 million would be approximately $40 / tonne (assuming a 3% government discount rate for emission reductions over 30 years).[54]

Whether the grant is recoverable or not does not affect its impact on the base case gap since it would only be recoverable if actual gas and carbon prices rise above the assumptions in the base case analysis. A grant has a similar effect as capital cost reductions, although capital cost reductions can have follow-on effects in terms of ongoing maintenance costs and property taxes. For the purposes of enabling scenarios, grants are assumed to reduce the gap for existing customers roughly one-for-one.

9.3 PROVINCIAL OFFSETS

In the absence of grants, one tangible way for the Province to support the Fuel Switch project is through the purchase of offsets under its carbon neutral government commitments. In 2010, the Government of B.C. committed to become carbon neutral. This legislated commitment applies to core government operations, school districts, health authorities, crown corporations, universities and colleges. The Ministry of Environment's

53 This assumes the same 3% discount rate as in the calculation of the implied carbon cost for B.C.'s electric vehicle program.
54 Treasury Board Secretariat guidance recommends a social discount rate of 3% for evaluating project costs and benefits in circumstances where environmental and human health impacts are involved. See: https://www.tbs-sct.gc.ca/rtrap-parfa/analys/analys-eng.pdf

▲ *The purchase of carbon offsets is one tangible way for the Province to support the Fuel Switch project.*

Climate Investment Branch is responsible for investing in and managing a portfolio of B.C.-based offset projects to meet the Province's carbon neutral commitments.

Regulated offset projects in B.C. must meet the requirements in the Greenhouse Gas Emission Control Regulation under the Greenhouse Gas Industrial Reporting and Control Act. The Regulation sets the framework for developing projects and creating offsets. Independent validators and verifiers provide third-party reviews to ensure offsets are real, verifiable, incremental and permanent. The Province typically purchases offsets for a maximum term of 10 years (with an option for renewal). However, the volume can also vary over the term. For example, the volume of offsets from the Fuel Switch could decline over a 10-year term as the reduction requirements for existing buildings are phased in. Similarly, the project could generate excess reductions in early years as new development is built out.

In 2015, the Province purchased 624,585 tonnes of GHG offsets to meet its carbon neutral commitments.[55] The bulk of these offsets were from the forestry sector, including investments in forest sequestration, and fuel switching in the pulp and paper sector from natural gas to wood residues. In 2015, the government purchased offsets for $9 - $15 per tonne. The Province in turn charged PSOs $25 / tonne for their offset requirements. The difference is to cover administrative costs for the program.

The Province will require new offsets as its existing portfolio of projects begins to expire in the next few years.[56] The Province expects to require over 650,000 tonnes per year of new offsets by 2021. In July 2016, the Climate Investment Branch issued a new Request for Offset Units (RFOU). Under the RFOU, applications will be accepted on a rolling on-going basis until July 19, 2021. The Province has also indicated a desire to diversify its portfolio, including securing offset projects within the building sector.

The Province's desire to diversify its offset portfolio suggests that it will need to purchase offsets at higher prices than previous years. A study commissioned by the Province and conducted by RDH (discussed in more detail in Section 10.5) recommended an offset cost of $30 - $70 per tonne for offsets in the building

55 The 2015 Year in Review is available at http://www2.gov.bc.ca/assets/gov/environment/climate-change/reports-and-data/cng/cng-yir-2015-final5.pdf

56 B.C.'s liquefied natural gas (LNG) industry may also require offsets to meet its emission benchmark.

sector. Despite these findings, the Province has established a target to purchase at least 50% of offset units at, or below, $8.50 / tonne. It is not really clear how the Province will achieve its target volume or diversification with quality offsets at such a low price, particularly given low natural gas prices and carbon taxes. This also stands in stark contrast to the implied carbon price in government programs such as rebates for electric vehicle (see preceding section on grants).

The Fuel Switch represents a potentially large and immediate source of high quality offsets for over 200 buildings that could be secured with considerably less effort than a program of individual building retrofits.[57] The regulated open books nature of this project offers considerable transparency on costs, and there is a well-established and easily verifiable GHG baseline for existing customers.

The total GHG reductions from the Fuel Switch are equivalent to about 13% of the GHG offsets purchased by the Province in 2015. However, only reductions from voluntary purchases would be eligible for sale as offsets. This means any GHG emission reductions allocated to new development with formal carbon performance standards could not be sold as offsets. This would include sales to SEFC. GHG reductions for PSOs would also not be sold as offsets. PSOs would be able to use the purchase of energy from the Fuel Switch to avoid the purchase of offsets from the Climate Investment Branch. It is likely that other levels of government (federal government and City) would want to retain the GHG reductions for their own use. However, any unallocated emission reductions or reductions from voluntary purchases by existing non-governmental customers or buildings with no formal carbon performance requirements could be eligible for sale as offsets. The sale of offsets could in turn be used to reduce or phase in the allocation of reductions to existing buildings. Under provincial GHG accounting rules, the City can still take credit within its community emissions inventory for all reductions sold as offsets.

Table 39 illustrates the possible contribution to the gap under different scenarios for offset sales. All volume scenarios are below the maximum volume of 100,000 tonnes established by the Province for any single project. The upper volume (56,000 tonnes/year) represents the available emission reductions for existing non-government buildings under base case assumptions. The middle scenario (50,000 tonnes/year) assumes part of the Fuel Switch output is allocated to SEFC, which is not eligible for offset sales (see section on Alternate Allocations of Fuel Switch below). The lowest scenario is simply intended to reflect a partial sale of reductions for existing buildings. All scenarios assume a constant volume of offsets for the specified term. The 20-year term captures the effect of a potential for renewal beyond 10 years. The offset values reflect a range based on the RDH report above. Validation and verification costs are not considered but given the large volume, established baseline and open books nature of the Fuel Switch project, validation and verification costs per tonne should be substantially lower than those assumed in the RDH report for individual building retrofits.

Table 39: *Present Value of Different Scenarios for Offset Sales ($millions)**

OFFSET VALUE	30,000 TONNES/YEAR		50,000 TONNES/YEAR		56,000 TONNES/YEAR	
	TERM					
	10 YEARS	20 YEARS	10 YEARS	20 YEARS	10 YEARS	20 YEARS
$8.50 / tonne	1.9	2.9	3.1	4.9	3.5	5.5
$20 / tonne	4.4	6.9	7.4	11.5	8.3	12.9
$45 / tonne	10.0	15.5	16.6	25.9	18.6	29.0
$70 / tonne	15.5	24.2	25.8	40.3	28.9	45.1

* Reflects possible reduction in gap from offset sales under base case assumptions.

57 The Fuel Switch project does not preclude envelope upgrades in individual buildings over time, which could be used to then free up capacity to serve new development.

Most of the offset price scenarios in Table 39 are higher than the Province has paid to date, and higher than the target average price in the Province's recent RFOU. However, that target price is intended as a portfolio average and not necessarily a cap on individual projects. Further, there is no real evidence the Province will be able to secure a more diversified portfolio of new offsets at the same price as its current portfolio given continued low natural gas prices and carbon taxes (as evidenced in the RDH study for building retrofits). To date, the Province has typically paid fixed prices for offsets. The study team has also proposed a novel dynamic pricing approach to offsets from the Fuel Switch. In exchange for a higher starting price (ceiling price), the actual price could be adjusted downwards over the term of the contract if gas or carbon prices rise above the forecast for the initial sale. This dynamic pricing approach would address the current gap / investment risk under low gas and carbon price forecasts, while ensuring the Province receives the benefit of higher gas prices or future increase in carbon taxes, similar to the proposed approach for recoverable grants.

Under the range of prices and terms in Table 39, offset sales are not enough to bridge the entire gap. However, offset sales could be combined with project optimizations, federal grants, the City's financial enabling tools, and/or voluntary subscriptions. In fact, the purchase of offsets by the Province could be one strategy to show provincial support in a grant application to the federal government. Alternative allocations of the project output or GHG reductions could affect the volume of offsets available for sale from the project.

Creative Energy has already submitted a preliminary Project Information Document (PID) to the Climate Investment Branch. This is the first step in securing an offset sale to the Province. The document was submitted in summer 2015 but will need to be updated to reflect the updated RFOU issued by the Province in 2016, updates to the project assumptions, as well as the proposed dynamic pricing approach to offsets. Creative Energy cannot finalize a sale of offsets to the Province until confirmation from the City regarding other enabling tools and the acceptability of offset sales to address the residual project gap.

9.4 CITY FINANCIAL ENABLING TOOLS

The Fuel Switch project is intended to address City policy objectives for renewable energy and GHG emission reductions. The City has a considerable role to play in the policy framework to facilitate the Fuel Switch, including policies related to new development (discussed below). The financial gap and investment risk for the Fuel Switch project is also due in part to a lack of policies to support carbon reductions in existing buildings and a lack of clarity over possible future policies. In addition, the City can play a role in offsetting the financial gap and investment risk for existing buildings. The City can also demonstrate leadership through the purchase of low-carbon energy / GHG offsets for buildings it controls.

There are two main financial enabling tools the City could use. The first is a rationalization of property taxes. The second is a deferral of land rent, deferral of residual property taxes and/ or deferral of payments for the use of certain infrastructure that could be owned by the City. City ownership of infrastructure may help to secure certain design optimizations, property tax rationalizations and/or grants. The City could also use 100% debt financing to lower the carrying cost of certain infrastructure. The intent of the City deferrals would be to cover investment risk under current assumptions for project costs as well as gas and carbon price forecasts. The recovery of these deferrals could be linked to reductions in project costs (e.g., design optimizations secured by the City), increases in gas and carbon prices beyond current forecasts, or other sources of revenue such as sales of low-carbon energy or offsets to new development or to the Province. Commitment of City financial enabling tools could be used to advance the development of this important but time-sensitive project while Creative Energy and the City pursue other enabling strategies that would reduce ultimate reliance on these enabling tools, including federal grants.

9.4.1 Rationalization of Property Taxes

Projected property taxes make up over 10% of the cost of the Fuel Switch project and nearly one quarter of the financial gap under base case assumptions. Reducing the property tax burden is a key enabling tool for the City of Vancouver and senior levels of government.

The bulk of the property taxes associated with the Fuel Switch project are incremental taxes. Creative Energy does not currently pay property taxes on existing distribution assets. Instead, Creative Energy pays a municipal access fee of 1.25% on gross revenues for access to City streets.[58] Creative Energy may, in turn, claim any real property taxes on distribution assets against the municipal access fee payable to the City. Given the relative value of the new interconnection, the study team opted to include full property taxes on the interconnection as part of the base case analysis for the Fuel Switch project. There is ongoing uncertainty over the assessment of thermal distribution in B.C..[59] Using the installed cost, the level of potential property taxes on the interconnection could exceed the credit available on Creative Energy's municipal access fees. Property taxes on the interconnection are entirely incremental because the interconnection would not exist in the absence of this project, and the asset has no impact on property taxes available from other activities. The City could address property taxes on the interconnection through changes in Creative Energy's Municipal Access Agreement or through ownership of the interconnection.

There would also be property taxes owed on the new plant. Creative Energy's customers already pay full property taxes on the existing Beatty Street plant, and this plant will be retained for peaking and back-up purposes. The Fuel Switch project is a discretionary project for existing customers. And like most low-carbon technologies, the plant will require more space and higher capital costs than a conventional gas plant, which in turn will result in higher property taxes than a conventional steam plant.

The impact of property taxes is exacerbated by the unique tax treatment of utilities in B.C. British Columbia is the only Canadian province or territory with a separate property tax class for utilities. Some Canadian provinces have separate property tax classes for oil and gas pipelines, but most do not. And no other province has a distinct rate that applies to energy distribution utilities. Many provinces only permit two property tax classes: residential and non-residential.

In Vancouver, the utility mill rate is more than three times the rate for light industry or businesses, and even higher than the rate for major industry (Figure 35). The City's portion represents about 67% of the total mill rate for utilities in Vancouver; the remainder is for other taxing authorities.

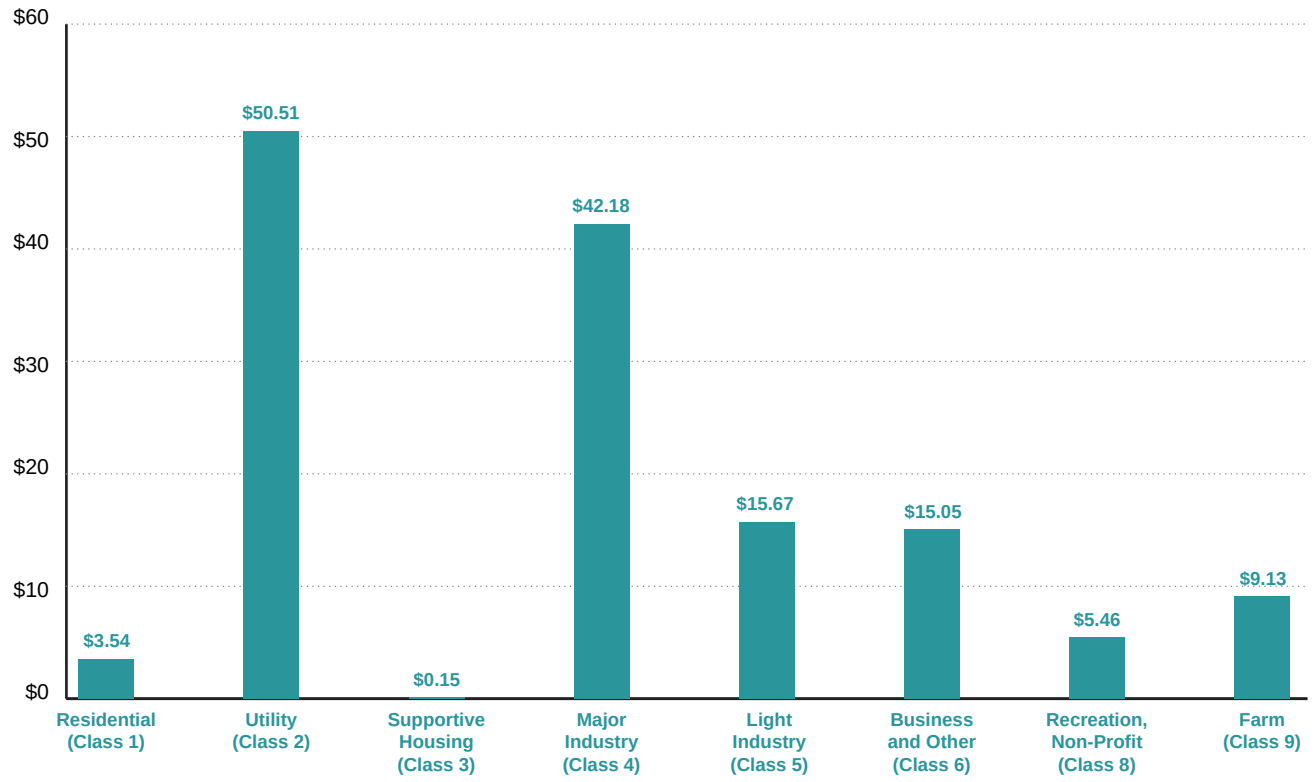
Property taxes are not easily compared across jurisdictions since mill rates, assessed values and total tax receipts are interconnected and depend on local context. Nevertheless, it is instructive to see how the Fuel Switch project might be taxed in other major Canadian cities. Figure 36 compares the Vancouver utility mill rate with the most likely mill rates for a similar project in Calgary or Toronto.

In Calgary, both the plant and the interconnection would attract the non-residential mill rate of $14 per thousand. There would be no tax due on the plant equipment – only on the land and building. The plant building and land would be assessed by the municipality. It is not clear how the interconnection would be assessed. Alberta does have a separate Linear Property Assessment Unit (LPAU), which is responsible for assessing major

58 This approach to taxation also puts some additional drag on discretionary efficiency or low-carbon projects that result in higher rates.

59 The valuation and taxation of district energy infrastructure in B.C. is relatively new. For other linear infrastructure, such as gas pipelines, the BC Assessment Authority uses a pre-defined schedule of values based on pipe size and length. Despite numerous requests, the Assessment Authority has yet to provide formal guidance on the assessment approach for district energy infrastructure. This represents a major impediment to investment in new (largely discretionary) low-carbon district energy systems in B.C. District energy systems provide a full service (heat) rather than a fuel, and they compete with on-site fuel conversion systems that do not normally attract any property taxes. An additional issue is that property taxes are normally based on installed assets rather than revenues. Where district assets must be built in advance of loads / revenues, this creates an additional barrier to investments in new energy infrastructure that could result in long-term cost savings for consumers, larger emission reductions and/or greater energy security.

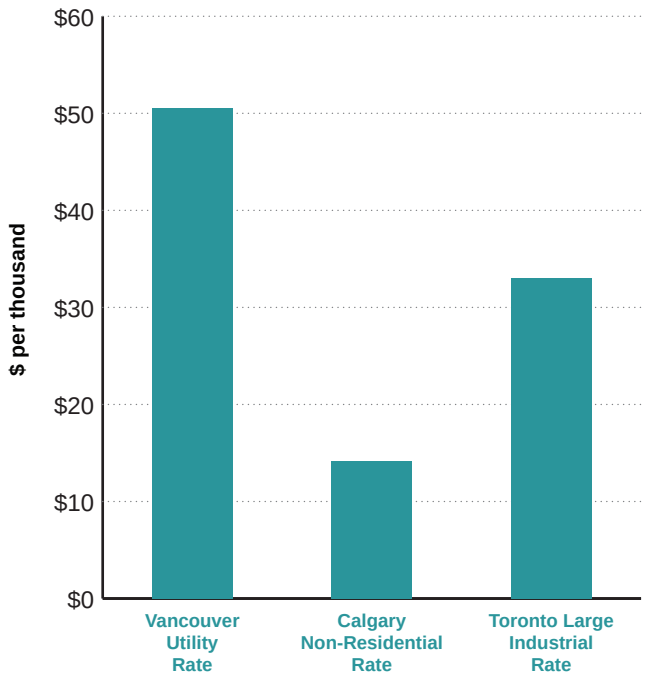
Figure 35: *2015 Vancouver Property Tax Mill Rates (per $1,000 of taxable value)*



resource-related linear infrastructure such as oil pipelines. Recent assessments from the LPAU are indicative of assessed values for linear infrastructure in Alberta, and range from $440 - $940 per meter.[60] This is significantly lower than the potentially $7,000 per meter assessed value for the Fuel Switch interconnection based on the information provided by the BC Assessment Authority.

In Toronto, there are several mill rates which could potentially apply to this project, ranging from $27 (Commercial) to $33 (Large Industrial) per thousand. Like B.C., Ontario has a provincial assessment office (the Municipal Property Assessment Corporation). The Province typically designates fixed rates for assessing linear property, though no information is available on the assessment rates that might apply to a steam interconnection.

Figure 36: *Vancouver Utility Mill Rate vs Other Jurisdictions*



60 See discussion of Polaris project and Komie North Extension in Municipal Affairs Linear Property Assessment, 2015 Annual Report, p 4.

Table 40: Property Taxes Before and After Rationalization (all values rounded)

	COV PORTION	OTHER TAXING AUTHORITIES	TOTAL PROPERTY TAXES	PROPOSED RATIONALIZATION
Land (net of credit from rooftop farm)	$7 million	$3 million	$10 million	$4.6 million
Building	$10 million	$5 million	$15 million	$6.9 million
Interconnection Pipe	$10 million	$5 million	$15 million	$0
Total	$26 million	$13 million	$39 million	$11.5 million

The target site for the Fuel Switch plant would likely not attract property taxes at the utility mill rate under any other conceivable use. As a result, a large portion of the property taxes for the site being carried in the base case analysis would be entirely incremental taxes to the City. Table 40 shows the present value of property taxes for the City of Vancouver and other taxing authorities under base case assumptions for various project components. A first step to addressing the financial gap would be to rationalize property taxes by exempting the interconnection pipeline from property taxes, and reducing the property taxes on the land and building for the Fuel Switch plant to the Business and Other mill rate. This reflects the current taxation of Creative Energy's distribution infrastructure and the most likely alternative use for the target site of the Fuel Switch plant. This rationalization alone would reduce the financial gap by $27.5 million before other optimizations or enabling strategies, and would still generate $11.5 million in property taxes from the target site. These residual taxes could in turn be deferred as part of the second set of financial enabling tools below.

This rationalization of property taxes could be achieved through changes to the Municipal Access Agreement and/or City ownership of the interconnection, together with a gross lease on the City-owned site that includes property taxes in lieu that are equivalent to the Business and Other mill rate.

9.4.2 City Ownership of Infrastructure and Deferral of Costs

There are several other financial enabling tools available to the City. The City could defer land rent and residual property taxes for the plant site, tying recovery of these to future increases in natural gas and carbon prices or additional revenues (e.g., greater allocation to new development, as discussed below). The City could also own portions of the infrastructure (e.g., the interconnection and/or the building that will house the plant). The City could in turn finance those pieces of infrastructure with 100% debt and/or tie recovery of those costs to future gas and carbon prices. In the absence of substantial changes in gas and carbon prices, the present value of the maximum City financial commitments could be $30 – 60 million. The lower boundary assumes the City only owns the interconnection and land, and defers land rent, property taxes (for the plant site), and fees for use of the interconnection. The lower boundary also assumes the City is successful in securing the interconnection optimizations. The upper boundary assumes the City would also own the building and defer payments for the use of the building. Except for debt financing costs on new infrastructure, the bulk of the City's financial enabling tools would be in the form of deferred revenues. However, the City has indicated it would only consider ownership of the building housing the Fuel Switch plant if this was offset by grants. The City could also choose to own the building and not defer payments for the building but base payments on 100% debt financing for the building. Excluding ownership of the building entirely, the value of City financial enabling tools would be equivalent to $30 - $40 million. This represents a theoretical limit to City financial enabling tools. The City could reduce the need for deferrals or recover deferrals through several means:

- additional grants secured after initial commitments of City financial enabling tool;
- additional allocations of energy to new development (increasing revenues at full project cost);

- securing additional project design optimizations;
- future increases in gas prices or carbon taxes beyond current forecasts;
- introduction of policies that require GHG reductions in existing buildings (thereby increasing the value of the Fuel Switch to existing buildings);
- higher volumes or premium from voluntary subscription process (see next section); and/or
- sale of offsets to the Province.

9.5 VOLUNTARY SUBSCRIPTION PROCESS FOR EXISTING BUILDINGS

Initial development and major extensions of Creative Energy's existing steam network were originally secured with long-term customer contracts. However, most of Creative Energy's existing customers were connected many years ago and are now on month-to-month contracts. Creative Energy's current customer base is stable and rates for existing customers are competitive with on-site gas boilers. But a large new investment for existing customers in costlier low-carbon energy sources would be risky in the absence of new long-term contracts and/or formal carbon policies for existing buildings. Existing customers could simply install on-site gas boilers to avoid higher rates, thereby eliminating planned carbon reductions and stranding the investment.

Unlike new development, existing buildings in Vancouver have no formal carbon performance requirements. While the Fuel Switch represents a cost-effective source of energy for new buildings with formal carbon performance requirements (see benchmarks in Section 10), there is a premium for existing buildings using only conventional gas-fired energy. For the base case analysis in Section 8, the investment risk for the Fuel Switch is reflected as a financial gap arising from the difference between the forecast cost of service for the Fuel Switch project and the forecast avoided costs of gas-fired steam for existing customers. This analysis is conservative. In-depth interviews, market research and anecdotal evidence suggest some willingness to pay a premium for low-carbon energy among some types of customers. However, given the size of the Fuel Switch investment, any premium would need to be secured in long-term contracts. Prior to a final investment decision, Creative Energy intends on running a voluntary subscription process to confirm existing customer willingness to pay some premium for low-carbon energy. This voluntary subscription process would also extend to other existing buildings not yet connected to Creative Energy.

The voluntary subscription process alone is unlikely to be sufficient to bridge the entire financial gap under base case assumptions, particularly given today's low gas and carbon prices and lack of clarity on future carbon prices or policies that may eventually apply to existing buildings, but the subscription process could still make an important contribution to the financial gap. Given the time and resources required, Creative Energy does not expect to undertake this process until confirming other enabling tools to bridge the financial gap. The success of the subscription process could also be enhanced with greater clarity on future carbon policies that may affect existing buildings. All levels of government can also demonstrate leadership by purchasing low-carbon energy for their own buildings. Creative Energy would also require confirmation of key project parameters from the City (e.g., land lease, property tax optimization, etc.) to inform the subscription offer.

Creative Energy anticipates at least two subscription offers. One would be aimed primarily at government buildings, both existing customers of Creative Energy as well as other existing gas-fired government buildings not yet connected to district energy. This offer would reflect the full cost of service for the Fuel Switch project (net of final optimizations, property tax rationalizations, and grants) similar to the offer for new development with formal carbon performance standards. PSOs in B.C., which make up about 12% of Creative Energy's existing customer base, already have additional avoided costs for purchasing offsets under B.C.'s carbon neutral government commitments. Future offset costs are uncertain. City and federal buildings, which make up about 5% of Creative Energy's existing customers, also

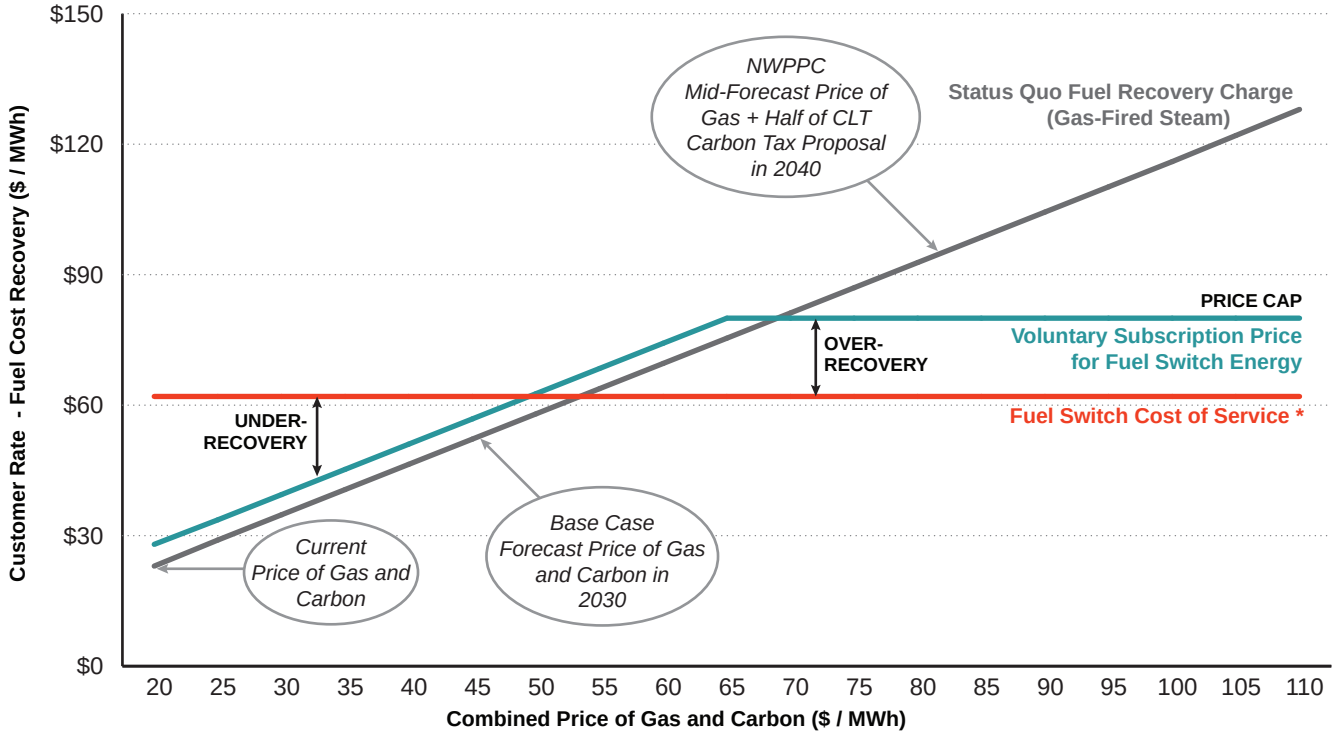
have formal commitments to acquire clean and low-carbon energy. The Fuel Switch represents one of the most cost-effective sources of deep carbon reductions for existing government buildings downtown. Government leadership could also enhance participation of non-government buildings in a voluntary subscription process. The sale of Fuel Switch energy to existing government buildings at full cost of service could reduce the financial gap by $27 million, more if other government buildings not yet connected to district energy were to participate.

The second offer would be aimed primarily at non-governmental customers and buildings. In-depth interviews and anecdotal evidence suggests a willingness among some large commercial customers to pay some premium for low-carbon energy. In some cases, the willingness to pay some premium relates corporate commitments for GHG reductions and renewable energy. Some building owners may also want to recertify their buildings to attract tenants with such commitments. Given most of the cost of energy for the Fuel Switch would be fixed, some customers may be willing to pay a premium simply to reduce their financial exposure to very uncertain and volatile gas and carbon prices. Large commercial buildings make up about 30% of Creative Energy's existing customers. Small commercial customers and residential stratas tend to be much more price sensitive and while they would be eligible to participate, Creative Energy does not anticipate substantial uptake from these customers. There is some additional complexity to contracting residential stratas given the collective nature of purchase decisions required by strata councils and/or strata members.

Creative Energy does not anticipate that private buildings would be willing to purchase significant volumes of low-carbon energy at the full cost of service for the Fuel Switch project, at least not under current gas and carbon prices or carbon policies. Instead, Creative Energy proposes a voluntary offer that would allow existing buildings to purchase a customer-determined volume of low-carbon energy at some premium above current gas and carbon prices but still below the full cost of service for the project. Customers could also elect to increase the portion of low-carbon energy they purchase over the term of the contract. Under Creative Energy's current rate structure, gas and carbon costs are part of a separate Fuel Cost Recovery Charge (currently about 55% of a typical customer bill) so the voluntary premium would be on the Fuel Cost Recovery Charge of customer's bill. The underlying Fuel Cost Recovery Charge would continue to escalate with increasing gas and carbon prices. However, it would be capped at some price above the cost of service for the Fuel Switch project. This would allow the possibility of some recovery of previously deferred costs and/or grants under conditions for low gas and carbon prices. Figure 37 shows an example of a possible voluntary offer. Additional enabling tools would still be required to address the residual gap and investment risk for the Fuel Switch project.[61] But this voluntary subscription process would reduce the magnitude of other enabling tools required and provide additional demand security for the Fuel Switch project. The subscription process could also be combined with certain enabling tools. For example, the GHG reductions associated with voluntary subscriptions from existing buildings which have no legislated requirements for carbon reductions could also be eligible for sale as offsets to the Province. The sale of short-term offsets would mitigate near-term rate impacts but still allow customers to secure cost-effective long-term reductions. It would also be possible to offer two prices depending on whether customers elect to retain near-term GHG reductions (preventing sale of offsets) or not. The portion of reductions sold as offsets could decline over the term of the customer contract. Based on preliminary market research and analysis, the study team expects a voluntary subscription process could reduce the financial gap by $5 – 10 million under current gas and carbon price forecasts before other enabling tools.

61 The Commission has allowed FortisBC to transfer the risk from selling RNG below actual cost to its much larger base of non-participating customers. In comparison to FortisBC's RNG program, the Fuel Switch represents a much larger share of Creative Energy's existing sales and ratebase.

Figure 37: *Example of a Voluntary Subscription Offer for Existing Private Buildings*



** Levelized cost after interconnection optimization and property tax rationalization.*

9.6 ALTERNATE ALLOCATIONS OF FUEL SWITCH ENERGY AND GHG REDUCTIONS

The Fuel Switch represents a very cost-effective means of meeting formal carbon performance standards for new development in Vancouver (see Section 10). Allocating more of the project to new development is one way to reduce the near-term financial gap. This strategy does not preclude advancing other projects in the future if and when GHG reductions are required for existing buildings. Rather it is intended to secure the most time-sensitive and cost-effective project fist.

The base case analysis in Section 8 assumes about 17% of the Fuel Switch output would ultimately be allocated to new development in NEFC and South Downtown. This assumption was based on discussions between Creative Energy and the City in the early stages of the feasibility study which contemplated neighbourhood energy agreements for both NEFC (negotiated during this study) and South Downtown. The addition of these two neighbourhoods would help to increase economies of scale for the project (which benefits both existing and new buildings) and to reduce the financial gap for existing buildings because of these greater economies of scale. Given formal carbon performance standards, there is a different cost benchmark for new development and the Fuel Switch project is a cost-effective means of meeting these standards. As a result, new development can cover its full cost of service from the Fuel Switch project and does not contribute to any financial gap.

Creative Energy and the City had expected to secure new development through neighbourhood energy agreements. These agreements would have secured both near-term developments as well as future development in these neighbourhoods. This security in turn would have supported investment in new hot water networks to serve the neighbourhoods as a whole, and also would have secured investments in much larger low-carbon projects such as the Fuel Switch in advance of full build out of the neighbourhood. As discussed in Section 2, the Commission has rejected the first such franchise agreement for

NEFC, largely over concerns about connection policies established by the City within those agreements that would provide the security for Creative Energy to advance new hot water networks and larger low-carbon supply projects. The Commission appears to be of the view that there are no economies of scale in low-carbon thermal energy systems and no other forms of market failure warranting connection policies. The City is now exploring other options to achieve its policy outcomes and to secure the benefits of larger low-carbon projects for future consumers.

In the absence of a franchise agreement, Creative Energy can still proceed with individual extensions based on near-term developer decisions. Depending on the location of near-term development there is no guarantee that individual extensions will be feasible in the face of uncertainty about future development.[62] Creative Energy also cannot use future development to secure a large investment in the Fuel Switch. Nonetheless, the study team has identified considerable near-term development both within NEFC and South Downtown, as well as other parts of downtown and Vancouver. The City could also employ other tools to secure the project for future development. One approach is for the City to provide financial security in lieu of load security, which could then be backstopped through other City controls over development. In addition, the City could develop networks itself and contract energy from the Fuel Switch for those networks. The City already has an existing network within SEFC and this system will require additional sources of low-carbon energy in the near future to meet ongoing growth.

Despite the cost competitiveness of the Fuel Switch, there are other market barriers to securing near-term development that may require policy support from the City. The current lead time for the Fuel Switch exceeds the lead time for many near-term developments. One of the purposes of the neighbourhood energy agreements was to address the possible mismatch in timing between individual developments and a large and lumpy low-carbon supply project such as the Fuel Switch. The neighbourhood energy agreements would have transferred carbon performance requirements to the neighbourhood utility and in turn would have allowed the utility to optimize the size and timing of projects for the neighbourhood as a whole. The City will now need to establish a mechanism to allow near-term developers to receive appropriate credit for the future Fuel Switch. This will also require addressing conflicting policies. For example, even if the City acknowledges the project in terms of carbon performance standards, the City also requires LEED certification and LEED does not currently allow credit for future low-carbon projects at the time of certification, even where these may be superior in terms of cost and depth of reductions.

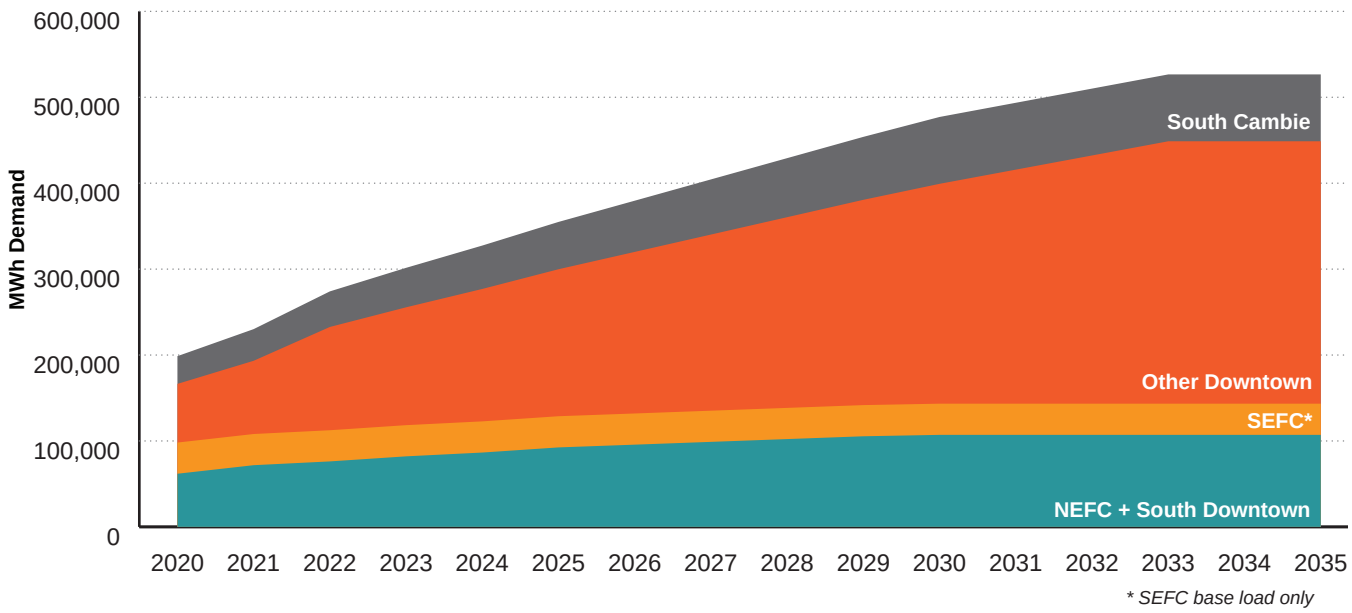
The City could also extend the amount of new development available to the Fuel Switch by allowing developers or neighbourhood energy systems not physically connected to the Fuel Switch to purchase unallocated GHG reductions from the project. In the absence of contracts with existing customers, Creative Energy can still displace gas-fired energy for these customers to generate a GHG reduction credit that can be transferred to other development and/or sold to the Province. This is not intended as a permanent solution but could help secure a time-sensitive and cost-effective project for the time when the reductions are required for existing buildings. This has the added advantage of allowing emerging neighbourhood systems to defer investments in costlier low-carbon energy sources until they reach sufficient scale to support larger low-carbon projects.[63]

Figure 38 illustrates the potential energy demand from new development in downtown, SEFC and South Cambie. There is considerable anticipated development outside NEFC and South Downtown, including infill development within the existing

62 In the face of load uncertainty, it may also be more expedient in some cases to extend the steam network rather than implement new hot water systems with added upfront cost and complexity, contributing to technology lock-in.

63 This use of credits is comparable to FortisBC's RNG program. RNG is being considered as a strategy to achieve Vancouver's renewable energy goals. However, RNG is not physically distributed to individual customers. Rather, RNG is generated and injected to the gas grid at a small number of sites in the province (none of which are within the City of Vancouver boundaries). The premium for RNG and notional environmental benefits are then banked and allocated contractually to individual participants in the program.

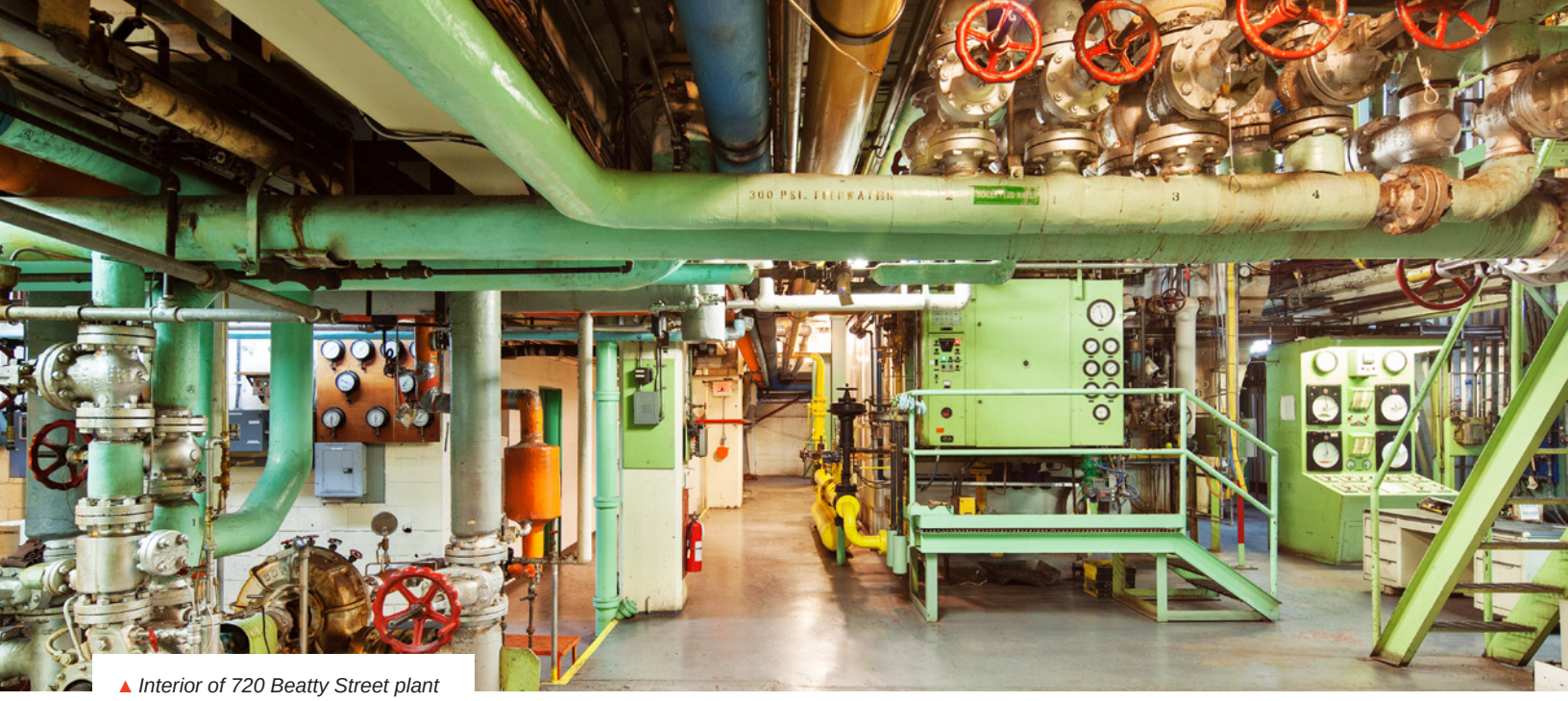
Figure 38: *Annual Energy Demand for Projected New Development in Downtown, SEFC and South Cambie*



Creative Energy steam service area and new development in the West End, Georgia Corridor, Downtown Eastside (including Chinatown), and False Creek flats. The projection of development potential downtown is very conservative. But assuming the City could secure the projected development downtown over the next 10 years, this would reduce the financial gap for the Fuel Switch by $15 – 20 million. This calculation assumes new development would only contract 75% renewable energy supply and also reflects the expected phasing of development.

SEFC is already served by the neighbourhood energy utility owned by the City of Vancouver, with similar connection policies to those that were proposed for NEFC. SEFC will require additional low-carbon energy to meet ongoing growth. The proposed Fuel Switch plant is located next to SEFC and based on the analysis in this report, the Fuel Switch could provide the next increment of low-carbon energy for SEFC at lower cost than adding a second heat pump within the City's existing sewer heat recovery plant. The City could support the Fuel Switch project by entering into a thermal energy purchase agreement for SEFC. This would lower near-term rate pressure for SEFC ratepayers. It would also not preclude advancing the second sewer heat pump in future, if or when additional low-carbon energy is required downtown.

The study team also considered new development within South Cambie. The Cambie Corridor is one of the target zones for the City's district energy strategy. Creative Energy was selected as a preferred proponent for the area known as South Cambie (south of 37th Avenue) and had undertaken analysis of potential loads as part of that process. While South Cambie cannot be physically connected to the Fuel Switch, it could still be incorporated into the project through a credit trading approach. This would be temporary, allowing Creative Energy to meet near-term carbon performance standards in South Cambie at a favourable cost while permitting time for loads and networks to reach a scale to support local projects. Again, this reflects a rational approach to planning low-carbon energy projects at a City scale. However, the City has made no decisions on the future of district energy in South Cambie or on the use of credits to help advance least-cost and time-sensitive projects first. If the City were to secure anticipated development in only a portion of the South Cambie neighbourhood, this would reduce the financial gap for the Fuel Switch by



▲ *Interior of 720 Beatty Street plant*

another $10 – 15 million.[64] The study team had no development information or insight on City plans for other proposed district energy zones in North Cambie or the Broadway Corridor.[65] The credit trading approach is particularly relevant to neighbhourhood systems because these systems are expected to have larger low-carbon projects that could be advanced in the future. But credits could also be used to meet low-carbon requirements in other development sites throughout Vancouver.

9.7 SUMMARY OF OPTIMIZATIONS AND ENABLING STRATEGIES

As will be shown in the next section, the Fuel Switch represents a substantial source of very cost-effective renewable energy and carbon reductions. The cost-effectiveness of this project is due in large part to its scale, but under the base case assumptions in Section 8, there is still a considerable financial gap for the Fuel Switch project for existing customers. This gap reflects conservative project assumptions and very low gas and carbon price forecasts. Current carbon prices and policies are not yet commensurate with government targets for carbon reductions. At the same time, the Fuel Switch is a potentially time-sensitive project.

Fortunately, as illustrated in this section there are a significant number of enabling strategies for the Fuel Switch project. However, most of these strategies will require action by the City and other levels of government. No single strategy will be adequate to secure this investment but there are several viable packages of strategies to eliminate the gap.

For example, securing the most promising interconnection optimizations and property tax rationalization alone would reduce the gap from $156 million (after taking into account the proposed federal floor on carbon taxes in 2022) to $117 million. A purchase agreement for SEFC would reduce the gap to $103 million. All three of these strategies are within City control and have no direct financial impact on the City, Leadership from all levels of government in acquiring low-carbon energy for government buildings would reduce the gap to below $75 million. The residual gap could be met through some combination of voluntary subscriptions, offset sales to the Province, increased allocation to new development, recoverable grants, and additional City financial enabling tools. Different scenarios for addressing the gap are discussed in more detail in Section 14.

64 While there is significant development potential, it will be built out more slowly than downtown

65 There is also a neighbourhood energy system under development for the River District neighbourhood in Vancouver. This system may be able to use credits in advance of other projects.

10. PROJECT ALTERNATIVES AND COMPARATORS

This section of the report reviews potential alternatives for achieving the carbon outcomes of the Fuel Switch. Some of these alternatives are only partial solutions. For example, a conversion of the existing steam system to hot water would provide some GHG reductions through efficiency improvements, but additional investments in alternative energy supplies would still be required to achieve the outcomes of the Fuel Switch. A hot water conversion would increase the number of viable low-carbon energy sources, although there is no evidence these alternatives would be lower cost than the Fuel Switch. A small sewer heat plant is a means of achieving carbon performance standards for new hot water neighbourhoods such as NEFC. However, sewer heat is not a viable alternative to generate steam and would not reduce emissions for existing steam customers. In addition to project alternatives, this section also compares the theoretical levelized retail rates for existing steam customers and for new hot water customers under various supply alternatives and to other low-carbon rate benchmarks.

10.1 STEAM TO HOT WATER CONVERSION

There are a limited number of technologies and fuels for producing low-carbon steam. Conversion of the existing steam system to hot water would provide some immediate GHG reductions through efficiency improvements. However, these reductions are minimal in comparison to the Fuel Switch project. Further reductions in emissions would require additional investments in new low-carbon energy sources following the conversion. The conversion to hot water would open up the feasibility of other low-carbon energy sources, where available and viable, including sewer heat, geoexchange and other sources of waste heat.

▲ *Interior of 720 Beatty Street plant*

Steam is still the most common distribution medium among large legacy district energy systems in North America (e.g., Toronto, Montreal,[66] New York, Boston, Philadelphia, Denver, Indianapolis, Cleveland, San Francisco, Baltimore, Seattle, etc.).[67] In Vancouver, there are also large steam distribution systems at the Vancouver General Hospital and Children & Women's Hospital campuses. Many downtown steam systems were first developed over a century ago at a time when most buildings required high supply temperatures under peak design conditions (cold weather), and when most downtowns still contained process steam loads such as hospitals and small industry. Many of these steam systems were initially developed by electric utilities, which produced steam as a by-product from electric generating stations –

66 Montreal has an older steam system as well as newer hot water systems.

67 District Energy Inventory for Canada, 2014. Prepared for CanmetENERGY, Natural Resources Canada Environment Canada and CIEEDAC Supporters. Prepared by: John Nyboer Noel Melton of the Canadian Industrial Energy End-use Data and Analysis Centre Simon Fraser University, Burnaby, BC. March, 2015. Available online at: https://www.cieedac.sfu.ca/DB_DEnew/DEFinal2015.pdf

the earliest examples of CHP[68]. In fact, district heating was important for the early development of new electric systems in urban areas, helping to increase the efficiency of electricity generation and providing an important source of additional revenue for early electric utilities.

Modern commercial and residential buildings do not require steam for space heating and domestic hot water loads. Virtually all greenfield district energy systems built in the last 10 – 20 years that serve only new commercial and residential development almost always use hot water distribution. For example, the City of Vancouver's NEU in SEFC produces and distributes only hot water. As noted by the European Commission: "Heat distribution is almost always done in modern systems using a network of pre-insulated pipes conveying hot water. In some older systems steam is used but this is not modern practice for a variety of reasons."[69] Where there is a requirement for process steam, the need is often limited (e.g., sterilization in hospitals) and these needs can be met through small-scale steam generators or other technologies.

Many large single-owner institutions with old steam systems have converted from steam to hot water as their building stock has been modernized and the need for process steam has decreased. A notable local example is UBC. Parts of the UBC steam system were almost 100 years old, and the system had very high losses due to the complete deterioration of insulation in some areas. In an effort to save costs and lower its GHG emissions, UBC elected to replace its entire steam system with hot water over the span of a few years. The project cost over $85 million (including a new gas-fired hot water plant). Some older buildings required major upgrades to accommodate hot water, and the system must operate at slightly higher temperatures than networks serving only new construction. On-site alternatives for sterilization and other process loads also needed to be implemented.[70]

A hot water conversion is much more challenging in a commercial system with multiple customers. In some cities, legacy steam systems were abandoned in the face of major investment requirements and a lack of public policy at the time (e.g., Portland, Oregon). Many of these cities are now trying to recreate modern district energy infrastructure from scratch to meet new policy objectives for energy security and climate protection. Where legacy steam systems have survived, there is now greater interest in how to support a phased conversion rather than start entirely from scratch.

The first heating network in Copenhagen started in the city centre in 1925. By 1970, the network supplied about 34% of Copenhagen's heat demands. Beginning with the oil crisis of the 1970s, Denmark introduced a series of policies that stimulated the growth of district energy including heat planning laws; mandatory connection zones; bans on electric heating; policies and incentives to support CHP; and policies, incentives and taxes to promote low-carbon energy. Today, this district heating network now encompasses 160 km of transmission pipes and 1,500 km of distribution pipes (Figure 39). This network, one of the largest in the world, now supplies 98% of the heating needs of Greater Copenhagen. The system includes ten major CHP stations, three heat storage facilities, several peaking plants, smaller alternatives energy sources, and numerous pumping stations. The initial network, which served mainly hospitals and industry, was based on steam. When the system was expanded to residential and commercial buildings, a parallel system based on hot water was established. With declining need for process steam, Copenhagen embarked on a long-term plan to replace steam pipes with hot water. The project commenced around 2000 and will be completed in 2025. A strong policy framework provided the necessary load security to support this transition to new infrastructure.[71]

68 See http://www.districtenergy.org/pdfs/IDEA_Industry_White_Paper.pdf
69 European Commission. 2012. Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practice and Measures of Promotion, Page 89. Available at: https://setis.ec.europa.eu/system/files/JRCDistrictheatingandcooling.pdf
70 More information on the UBC project can be found here: http://energy.ubc.ca/projects/district-energy/
71 For more information on the history of the district heating system in Copenhagen and the conversion to hot water, see for example: http://www.engineering-timelines.com/why/lowCarbonCopenhagen/copenhagenDistrictHeating_03.asp

Copenhagen's strategy is echoed in the District Heating Handbook, Fourth Edition, published by the International District Energy Association:

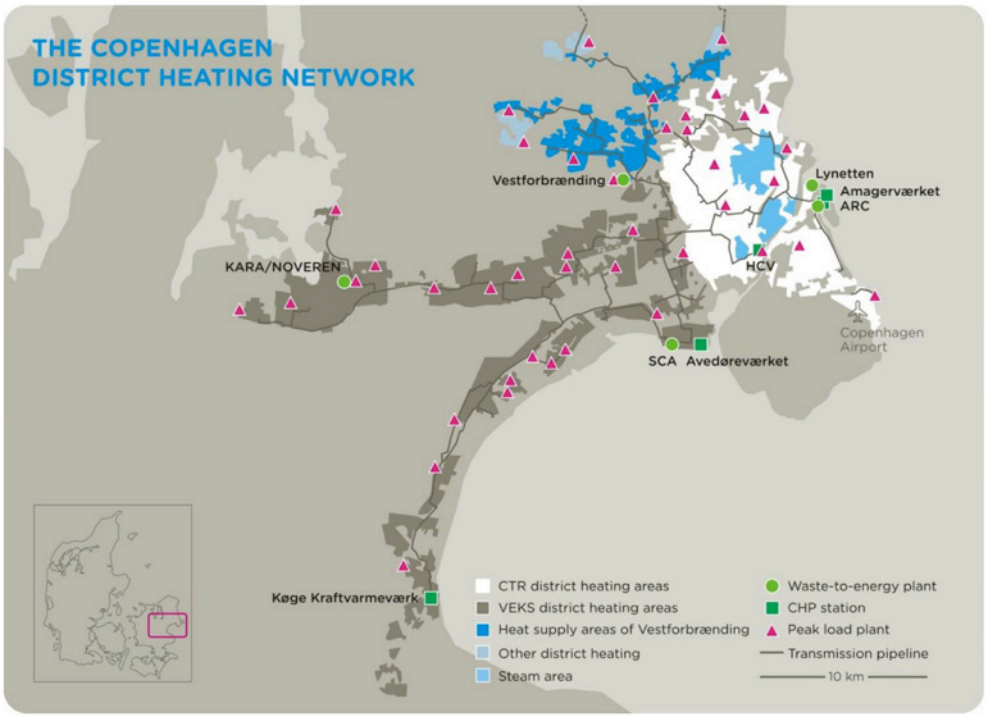


Figure 39: *The Greater Copenhagen District Energy Network**

** Network contains a mix of interconnected hot water and older steam networks. Existing steam networks are undergoing a phased and long-term conversion to hot water. Plans are to complete this conversion by 2025.*

"Where steam is provided and is already an essential part of an industrial commercial zone, it may be impractical to convert to hot water distribution. However, when new areas are developed (i.e., through urban renewal, rehabilitation or expansion) these may be appropriate for a hot water system. One way to develop hot water district heating is through the hybrid concept, where steam is transmitted for the distance necessary to meet customer commitments, then is fed into a heat exchanger and pumping system for a hot water loop. As customers' requirements change and areas are renewed, the hot water service area can be developed back toward the heat source in a step-by-step fashion. Long range planning must include consideration of phased elimination of heat exchanger stations and full conversion to hot water. Hybrid systems also can be incorporated into energy systems where steam or hot water is purchased from a separate facility." [72]

Creative Energy has already commenced the introduction of new hot water networks at the periphery of the existing steam system. Unfortunately, in the face of normal uncertainty in the location, timing and connection decisions of individual developments, it is often easier and less risky to simply expand existing network technologies. The transition to hot water requires vision, proactive planning, and adequate load security (customer and policy support). This is particularly important where the transition will require additional upfront investment in advance of customer connections (e.g., oversized steam to hot water converter stations). One of the purposes of the proposed Neighbourhood Energy Agreement between the City and Creative Energy for NEFC was to support such a transition to hot water for major new extensions. The City and Creative Energy were expecting to replicate this agreement for other major expansion areas. In light of recent Commission decisions that rejected this agreement, Creative Energy and the City are exploring other strategies to support the transition from steam to hot water for major new extensions.

Compared to many other legacy steam systems, however, Creative Energy's existing system is young with relatively low maintenance costs, low losses and many years of remaining life. Conversion of the existing steam infrastructure to hot water is also more complex and costly within a

72 The Handbook (Chapter 2, Page 16) can be found online at: http://www.districtenergy.org/district-heating-handbook/

dense downtown core. Creative Energy expects to undertake a phased conversion plan tied to major future maintenance or replacement projects within the existing network. Such a conversion will likely also require new long-term customer contracts in many circumstances.

For the purposes of the Fuel Switch Study, the team evaluated the hypothetical costs and benefits of an immediate conversion to hot water. Apart from opening up opportunities for other low-carbon energy sources, some of the main benefits of a hot water conversion are as follows.

- ***Lower Distribution Losses:*** Distribution losses in dense new hot water networks are typically 2 – 4%. For comparison, Creative Energy estimates steam distribution losses to be ~10%, plus additional losses in the energy rejected by customers in condensate, although there is still room for many customers to increase their heat recovery from condensate. Reduced losses are typically the main economic driver for a conversion from steam to hot water.

- ***Lower Construction Costs:*** Steam pipes are more compact than water pipes for transferring a given quantity of energy. However, new steam lines are also more expensive to install as they typically require manholes to enable inspection and maintenance. Nonetheless, there would be a premium to advance replacement of existing steam pipes with new hot water pipes prior to the end of their useful life.

- ***Lower Maintenance Costs:*** Hot water pipes typically have lower lifecycle maintenance costs compared to steam pipes.

- ***Simpler User Interface:*** A simple water-to-water heat exchanger is required at the interface with customer buildings. Billing is based on actual energy transfer via the heat exchanger. Customers do not need to deal with condensate or pay for energy rejected in the form of condensate. Virtually all of Creative Energy's customers convert steam to hot water for internal uses (e.g., space heating and domestic hot water). However, there are a few notable exceptions such as St. Paul's Hospital, some hotels and some large event spaces which use steam directly for sterilization, humidification, or laundry operations. These customers would require additional investments to meet these needs following a hot water conversion. Some older buildings may also require upgrades to envelopes, internal distribution systems and system controls to accommodate a lower supply temperature following a hot water conversion.

- ***Lower Water Use:*** Modern hot water systems have closed distribution loops with limited requirements for top-up water. Creative Energy's existing steam system has limited condensate return (primarily limited to customers located close to the Beatty Street plant). This is because condensate return systems are costly to install and they also tend to have high maintenance costs and shorter lives than steam supply systems. In Vancouver, the economics of condensate return have not justified significant investments. As a result, the steam system requires significant municipal make-up water, although most of this water use also coincides with the rainy season in Vancouver. Creative Energy is exploring opportunities to use rainwater rather than municipal water suppliers for a portion of its water needs. There are also many opportunities (possibly at lower cost) for individual customers to recover and reuse their condensate in order to reduce downstream, municipal water consumption (e.g., use in grey water systems, laundry, water features, landscaping, etc.). On-site condensate recovery and reuse can also provide customers with LEED points.

Table 41: Hot Water Conversion Capital Costs

ITEM	ESTIMATE DETAILS	CAPITAL COST [$000]
Remove and Replace Distribution Piping	Based on KWL Technical Memorandum, "Pipe System Conversion Cost Estimate" September 8, 2015	$52,800
Remove and Replace Energy Transfer Stations	215 x cost of $150,000 per ETS*, (includes design, existing ETS* demolition costs, and 30% contingency).	$41,900
Remove Steam Manholes	67 manholes at cost of $100,000 per manhole (includes design and 30% contingency).	$6,700
Total		$101,400

** Energy transfer station*

Table 42: Annual Savings from Hot Water Conversion

ITEM	ESTIMATE DETAILS	ANNUAL SAVINGS [$000/YR]
Fuel Savings*	11 - 15% savings on fuel consumption annually (base cost assuming current gas consumption of 1.9 million GJ/yr and $8 /GJ all-in cost, i.e. commodity, delivery, carbon costs)	$1,700 – 2,300
Water, Chemical, Maintenance Savings	Based on Creative Energy Director of Engineering estimates: • $500K/yr water savings • $100K/yr chemical savings • $50K/yr maintenance savings • $200K/yr in manhole rebuilds	$850
Labour Savings	Based on Creative Energy Director of Engineering estimate of 20% savings on $650K/yr	$130
Total Annual Savings*		$2,650 – 3,250
Carbon Emission Reductions*	11% efficiency improvement, avoiding emissions from natural gas heat generation	~10,500 – 14,500 tonnes per year

** The upper end of savings is based on average condensate heat recovery of existing customers. The savings from hot water conversion would be reduced if customers were already maximizing their heat recovery (scavenging) from condensate. The lower end of savings is what can be attributed to the hot water conversion alone assuming that customers have maximized use of heat in condensate.*

Table 41 shows a preliminary estimate for the upfront costs of a full conversion of the existing steam network to hot water.[73] An immediate conversion would cost more than $100 million. Table 42 summarizes the potential annual savings from the hot water conversion which include fuel, water, maintenance, and labour costs. The fuel savings are by far the largest expected savings and these are estimated from the energy balance diagrams in Figure 40. The net system efficiency after a hot water conversion would increase approximately 11 - 15%, saving between 10,500 - 14,500 tonnes of GHG emissions per year. The upper bound is based on the estimated average recovery of heat from condensate by customers. The lower bound reflects the net savings from a hot water conversion if all customers were already maximizing heat recovery from condensate (e.g., though heat scavengers to pre-heat domestic hot water). The capital costs and operating cost savings from the hot water conversion are both high level and somewhat optimistic. What the analysis illustrates is that an immediate hot water conversion represents a significant capital cost, even before further investments in alternative energy supplies, and the conversion itself would only save 10,500 – 14,500 tonnes of GHG emissions from efficiency improvements (compared to >80,000 tonnes for the immediate Fuel Switch).

While the hot water conversion would open up the possibility of additional sources of low-carbon energy, low-carbon energy sources have not been identified downtown with a comparable scale or cost to the proposed Fuel Switch.

73 Additional details contained in an accompanying technical memorandum prepared by KWL.

Figure 40: *Comparative Efficiency of Existing Steam System vs. New Hot Water Network*

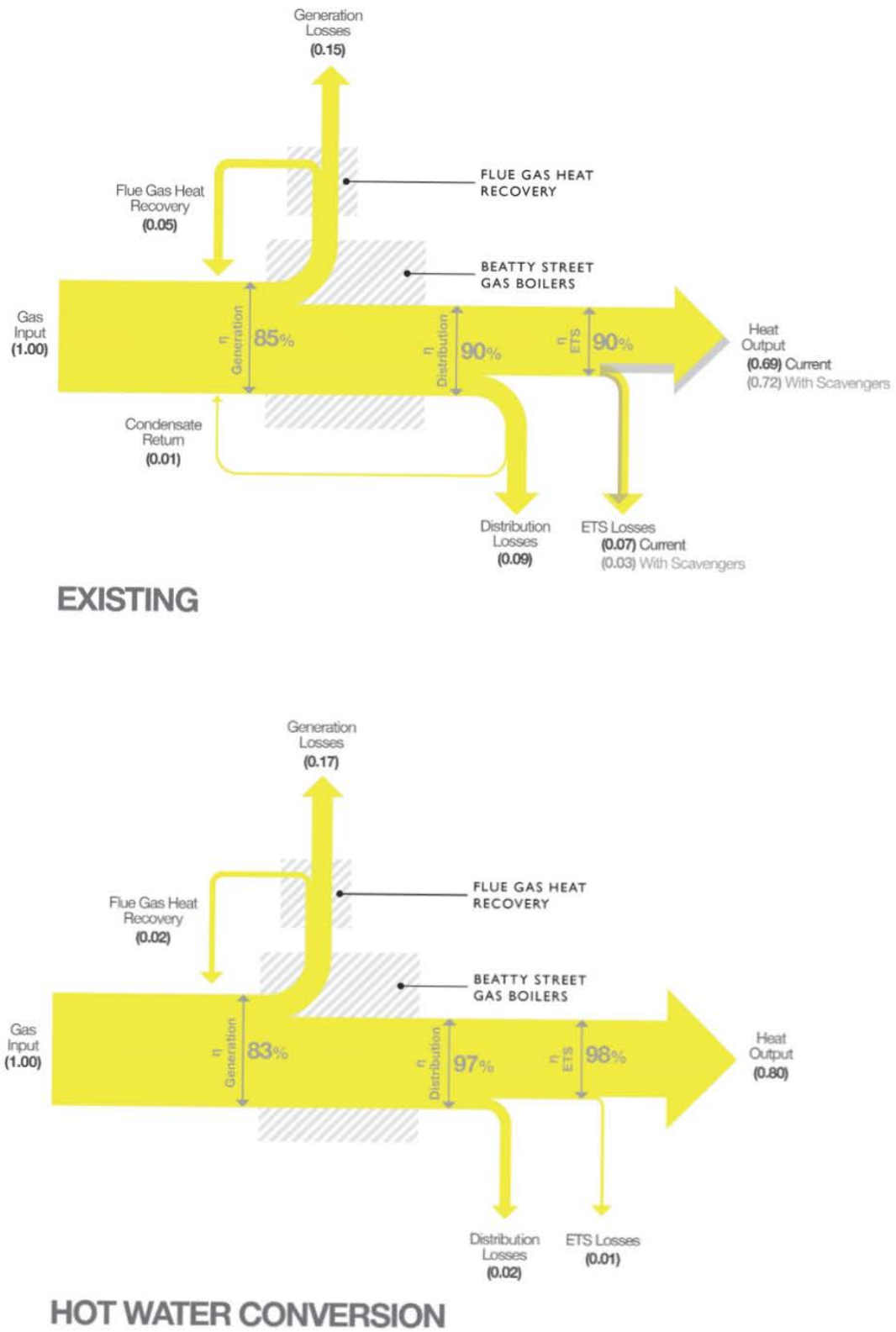


Table 43: Input Assumptions for NEFC Sewer Heat Plant

		NOTE
Capacity	6 MW	Sewer heat capacity. Peaking and back-up capacity provided by existing Beatty Street steam plant.
Annual Energy Production	36,000 MWh at buildout	Meets proposed carbon performance standard for NEFC at build out.
Capital Cost	$22.4 million (2020$)	Includes building and equipment, as well as allowance for interconnection of plant to NEFC network.
Coefficient of Performance (COP)	3.0	Reflects amount of heat produced per unit of electricity input.
Operators	1.5 FTE	
Levelized Production Cost (2020 – 2049)	$117 per MWh	Production cost only – excludes other NEFC costs such as distribution network, etc.

An immediate hot water conversion would be a complex undertaking and likely involve significant disruptions to residents and businesses downtown.

The Fuel Switch and the hot water conversion are not mutually exclusive. Creative Energy's proposed strategy is to decarbonize existing steam supply first, implement hot water networks for new neighbourhoods, and replace the existing steam network with hot water through a phased approach timed with major system maintenance or replacements. The introduction of hot water distribution will enhance opportunities for waste heat recovery and other forms of low-carbon energy to supplement and/or replace the Fuel Switch over time (with further growth in networks or at the end of the economic life of generating plants). Like new sources of low-carbon energy supply, load security (long-term customer contracts) will be required to undertake major new investments in hot water networks. This is why most of the major conversions to date in North America have occurred in large single-owner educational, health care and military campuses.

10.2 NEFC SEWER HEAT PLANT

Under the Neighbourhood Energy Agreement for NEFC that was rejected by the Commission, Creative Energy would have been required meet carbon performance standards for the neighbourhood as a whole. These requirements in turn were to be deferred to allow investment in a much larger project with potentially lower costs and higher GHG benefits. The most viable options available to Creative Energy include the larger Fuel Switch (which requires other customers beyond NEFC) or a smaller sewer heat recovery plant sized to supply the needs of NEFC customers only. This sewer heat recovery plant would be similar to the one developed by the City for its NEU in SEFC. Sewer heat recovery is not viable for producing steam so this technology would require a hot water distribution network. Further, there is not sufficient quantity of sewer heat to match the capacity of the proposed Fuel Switch and several distributed plants would likely be required to maximize the potential heat recovery.[74]

Table 43 summarizes the preliminary input assumptions and levelized cost of energy for the NEFC Sewer Heat Plant alternative. In this alternative, a plant would tap into the nearest viable source of waste heat at the sewer main on Quebec Street. The analysis is for low-carbon baseload energy supply only, which may be directly compared to the cost of baseload energy from the Fuel Switch (delivered to the Beatty Street plant). The network costs for NEFC are the same in all supply scenarios. Peaking and back-up to NEFC is provided from the existing Beatty Street steam plant under all supply scenarios. These network costs and peaking/back-up costs are part of the base retail rates for all scenarios.

74 While sewer heat recovery can be implemented at individual development sites, there are considerable economies of scale and integration (aggregation and diversification of heating demands and also sewer flows) for neighbourhood-scale systems.

The cost of energy from the NEFC Sewer Heat Plant would be about 60% higher than the cost of the Fuel Switch. However, the Fuel Switch would require a larger customer base to realize these savings. The comparative impact of each alternative on retail rates in NEFC is considered in the summary chart.

10.3 RENEWABLE NATURAL GAS IN EXISTING STEAM PLANT

One alternative to the Fuel Switch would be to purchase RNG from FortisBC for use in Creative Energy's existing steam plant. FortisBC acquires RNG from third parties under long-term contracts. Typical sources of RNG include gas recovered from landfills and anaerobic digestion plants producing gas from agricultural and food wastes. After sufficient clean up, biomethane is injected to the natural gas grid where it mixes with conventional natural gas. Customers that purchase RNG are not using RNG directly. Rather they are paying for and acquiring the attributes of RNG injected anywhere in the natural gas grid. Some of this RNG may also be banked credits from previous years where supply exceeded program demand. RNG is considered GHG neutral under provincial GHG accounting standards.

RNG has several potential advantages relative to the proposed Fuel Switch:

- RNG can be used in the existing steam plant and would not require additional capital investment by Creative Energy in a new interconnection or plant.[75]
- The purchase of RNG can be scaled to more directly match the demand for low-carbon energy, compared to a large and lumpy investment such as the Fuel Switch. For example, purchases of RNG could be phased more readily over time to reflect the phasing of low-carbon requirements for existing customers or the completion of new developments.
- RNG can be used to fuel existing gas boilers that produce both baseload and peaking energy.

The RNG alternative is relatively easy to evaluate since it only involves substituting RNG for a portion of conventional gas purchased for the existing plant. There would be no change in plant efficiency, no other changes in operating costs for the existing plant, and no additional capital costs. However, RNG is much more costly than conventional natural gas.

About 75% of existing gas use would need to be replaced with RNG to achieve the same carbon outcomes as the Fuel Switch. At build out of NEFC and South Downtown, this would require about 460,000 MWh (1.7 million GJ) of RNG per year. For comparison, FortisBC currently has six RNG supply contracts with a total forecast supply of 120,000 MWh/yr by 2021. Based on an expression of interest, FortisBC has estimated a potential supply of 420,000 MWh/yr.[76] The Commission has also established a cap of 420,000 MWh/year for acquisitions of biomethane by FortisBC. Current demand for RNG is forecast to be 88,000 MWh in 2016 up from 42,000 in 2015. Using RNG in lieu of the Fuel Switch would require FortisBC to triple its existing supply contracts and would exhaust the potential supply identified by FortisBC and the current cap imposed by the Commission.

Until recently, RNG was sold by FortisBC for $52 per MWh, more than three times the cost of conventional natural gas. In August 2015, FortisBC applied to the BCUC to reduce its Biomethane Energy Recovery Charge (BERC) rate.[77] FortisBC did not propose ways to reduce the underlying costs of RNG. In fact, the application suggested that the production cost of RNG could rise to as high as $61 per MWh by 2020.[78] FortisBC proposed to reduce the current BERC rate but also to tie the rate to underlying gas and carbon prices. FortisBC proposed a fixed premium of $25 per MWh ($7 per GJ) over

75 The purchase of RNG still requires upstream investments in new production plants.
76 FortisBC RNG Methodology Application: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/150828_FEI%20BERC%20Rate%20Methodology%20Application_FF.pdf
77 FEI BERC Rate Methodology proceeding, Exhibit B-1. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=510
78 Ibid, Section 4.3. RNG price of $17 per GJ = $61.20 per MWh.

the price of conventional natural gas plus carbon taxes, For example, with natural gas prices of $11 per MWh, plus carbon taxes on natural gas of $5.40 per MWh, the BERC rate would be $41 per MWh ($11.50 per GJ). Customers willing to commit to purchase at least 140 MWh per month for 10 years would be eligible for a slightly lower premium. Regardless, the premium for RNG is fixed, so the financial gap between steam generated with conventional gas and steam generated with RNG would no longer decline with rising gas and carbon prices, a key feature of the Fuel Switch. FortisBC proposed that the price reduction would be backstopped by all FortisBC natural gas customers. That is, any long-term shortfall between the cost of purchasing RNG and revenues from selling RNG under this new pricing methodology would now be recovered from all FortisBC customers. This new pricing methodology was approved by the Commission in August 2016.

Using RNG to achieve the same outcomes as the Fuel Switch would require substantial additions to current RNG supplies. The marginal production cost of RNG is a more appropriate benchmark to use for evaluating major new projects such as the Fuel Switch. This is a better indicator of real resource costs, excluding cross subsidies implicit in the new retail pricing methodology. Unfortunately, the long run marginal cost of RNG in B.C. is not known. For the purposes of this evaluation, the project team used a range from $43 per MWh, escalated at 1%, up to $54 per MWh, escalated at 2%. The latter is within the price cap established by the Commission, although there is no data to confirm that sufficient quantities would be available at this price. Further, this upper bound is still lower than the projected costs of RNG in 2020 from FortisBC's recent application. As a result, the analysis of this alternative may be considered optimistic. This analysis also assumes the price would be fixed and not vary with underlying gas and carbon prices. It is important to note again that although the current retail price is lower than $43 per MWh (the lower bookend used in this screening), this price is linked to underlying gas and carbon prices such that this option would quickly become more expensive than $43 per MWh under even modest increases in gas and carbon prices.

Under the range of assumptions for the marginal cost of RNG above, the levelized production cost for low-carbon steam using RNG would vary from $64 to $89 per MWh. This is above the expected range of production costs for the Fuel Switch, even before further project optimizations or other enabling tools. As with other options, the Fuel Switch and RNG are not mutually exclusive alternatives. While the Fuel Switch represents the lowest cost solution for significant baseload energy, RNG could play a role in system expansion or in decarbonizing peaking energy. It is likely that RNG would be the most cost-effective option to decarbonize peaking energy, although this would still be more costly than baseload carbon reductions.

10.4 ELECTRIC STEAM BOILERS

Electricity in B.C. currently has a low carbon content and represents an alternative to bioenergy for heating.[79] The summary retail rate comparisons in Section 10.6 include comparisons to electric resistance heat (typical benchmark for residential customers) as well as comparisons to other recent on-site systems that use electric heat pumps. This section discusses the possibility of Creative Energy using centralized electric boilers to generate steam in lieu of the Fuel Switch. Electric steam boilers have an average coefficient of performance (COP, a measure of efficiency) of just below 1 (essentially 100% of electricity is converted to steam). This is comparable to electric resistance heat. For comparison, a heat pumps can produce heat with a COP of 2.5 to 4+. However, heat pumps require sufficient sources of ambient heat (e.g., ground, sewers, air, industrial waste heat, etc.), and the higher COPs are contingent on higher quality heat sources (e.g., sewers are often warmer than ground or air and will result in higher COPs, all things being equal). Heat pumps also cannot produce steam and so centralized heat pumps are not a viable alternative to the Fuel Switch. Heat pumps could be deployed

79 Some of BC Hydro's energy supply is from biomass plants, several of which are electricity-only plants which recover substantially less useful energy from biomass compared to heating-only or combined heat and power plants.

following a full hot water conversion, but this would also require adequate sources of ambient heat.

Before undertaking a detailed analysis of the technical issues and capital costs of electric steam boilers, the project team conducted a high-level screening analysis of electric boilers. This analysis compared the variable cost of producing steam from electricity (i.e., ignoring capital and other operating costs) to the full lifecycle cost of the Fuel Switch project (before additional design options). Using the forecast Large General Service rate (the applicable rate for Creative Energy's existing plant), the electric boiler option is 2 to 2.2 times more expensive than the cost of the Fuel Switch, even before including capital and operating costs for the electric steam option. Even using BC Hydro's current rate for large industrial customers (transmission voltage) would not close the gap between electric boilers and the Fuel Switch.

There would be additional costs and considerations for the electric boiler option:

- The largest commercial offering from major industrial electric boiler manufacturers is about 4 MW. At this maximum offering, about 16 electric steam boilers would be required to match the baseload supply of the Fuel Switch. Creative Energy would still require the bulk of existing gas boilers for peaking and back-up. The existing plant would not be able to accommodate new electric boilers so a new plant would still be required, implying additional costs for site, building and interconnection. While these are already included in the Fuel Switch cost, they are not factored into the cost of the electric steam boiler option above used for screening purposes.
- In addition to the capital cost for new electric steam boilers, there would be additional costs to upgrade the electrical supply for a fully electric steam plant.
- Electric boilers typically have a shorter life than conventional gas or biomass boilers. This would increase lifecycle capital costs for this alternative.
- An electric boiler plant of this size would require full-time operators, although potentially fewer operators than a biomass plant.
- The bulk of the Fuel Switch costs would be fixed following initial plant construction, and Creative Energy also expects to enter into long-term contracts for urban wood waste. The future cost of electricity is highly uncertain and BC Hydro does not offer long-term contracts at pre-determined prices. The screening analysis used a conservative price forecast for electricity but this forecast does not recover all of BC Hydro's existing and projected future costs.

The electric steam alternative can be ruled out based simply on the cost of electricity. Including other costs such as incremental capital would only add to the cost premium for electric steam boilers vs. the Fuel Switch. This is not to suggest that electricity cannot or will not play a role in district energy. The Fuel Switch represents the least-cost option for generating steam. However, the potential supply of wood waste and the space available for a plant is limited. Additional sources of low-carbon energy will eventually be required with further growth of district energy networks in Vancouver. Electric heat pumps represent better value than electric steam or hot water boilers. Thermal networks provide the possibility for economies of scale in heat pump applications, centralized management of heat pumps, and the ability to tap ambient sources of heat not available or suitable at individual development sites. But heat pumps can also only be used in conjunction with hot water networks where there are adequate sources of heat. Over time, electricity could displace urban wood waste for downtown as the steam system is converted to hot water and the Fuel Switch plant reaches the end of its useful life. But the proposed Fuel Switch using urban wood waste represents the greatest near-term opportunity for significant and cost-effective GHG reductions in downtown Vancouver.

There are other important linkages between district energy and the electricity sector. The Fuel Switch could be designed to also produce electricity, offsetting not only other sources of low-carbon electricity generation but potentially new

▲ *Interior of 720 Beatty Street plant*

investments in local grid capacity. As discussed in Section 9, CHP does not contribute significantly to the project economics under current standing offer prices from BC Hydro and there are currently no other programs to capture possible transmission or distribution benefits from local generating projects.

In Denmark and other Scandinavian countries, thermal networks are also proving to be an important tool in the expansion of renewable electricity supply. Thermal storage of electricity is much less costly than battery storage. Electric boilers have been deployed not as a baseload energy source but to take advantage of intermittent electricity which may otherwise be dumped or sold at very low or even negative prices. Currently there are no time-of-use or other programs to capture the value of low cost intermittent or off-peak energy in B.C..

10.5 BUILDING ENERGY RETROFITS

The Fuel Switch achieves GHG reductions through low-carbon energy supply. As demonstrated in this report, the Fuel Switch represents one of the lowest cost incremental sources of low-carbon energy supply in Vancouver. The low costs of the Fuel Switch are achieved in part through large economies of scale. The team also explored what may be required to achieve comparable GHG reductions through aggressive efficiency upgrades for existing buildings. Creative Energy serves more than 200 existing buildings including commercial and residential buildings. The average annual heating energy intensity of existing steam customers is approximately 100 kWh / m^2 / year, which includes energy used for space heating and domestic hot water. Achieving a 75% emissions reduction from efficiency upgrades alone would require reducing the system-wide average heating energy intensity to 25 kWh / m^2 / year.

No estimate is available for the cost to achieve such large efficiency improvements in the 200+ existing buildings served by Creative Energy. These improvements would need to be undertaken by individual customers. Most analyses of energy retrofits group together all sources of reductions, including cooling, plug loads, ventilation, and heating. And many reports do not distinguish between demand-side measures and on-site low-carbon supply options such as heat pumps and solar panels.

Nevertheless, some generic information is available, which indicates the huge variation in costs for efficiency measures.

Recent research cited by the Rocky Mountain Institute (RMI) indicates that energy retrofits in existing buildings can reduce building heating intensity by ~10 – 30 kWh / m^2 / year (10 – 30% of current average energy intensity) at a capital cost of $108 - $800 per m^2.[80] Assuming the higher energy savings estimate of a 30% reduction in average energy intensity would translate to a GHG emission reduction of 35,000 tonnes / year and assuming the lowest capital cost for retrofits in RMI's range (a generic estimate for North America, not specific to any specific building type or vintage), the total cost of these program would be about $450 million. Using these optimistic assumptions and a utility discount rate of 5.95%, this would translate to an implicit carbon abatement cost $720 / tonne. This is much higher than the Fuel Switch, even before further design optimizations of the Fuel Switch, and would also produce less than half of the total emission reductions available from the Fuel Switch.

Another recent study, commissioned by the Province, suggests lower costs for building energy retrofits. In this study, prepared for the Climate Action Secretariat in 2015, RDH Building Engineering Ltd and the Delphi Group explored the potential for GHG offsets from building energy efficiency upgrades and retrofits.[81] The estimates are considered illustrative. The study considered three types of offsets in the building sector:

- energy upgrades for commercial buildings,
- fuel oil conversion in single family houses, and
- energy upgrades for multi-family residential buildings.

The energy upgrades for commercial buildings and multi-family buildings are the most comparable to the Fuel Switch project. The RDH study suggested energy upgrades of buildings could reduce emissions between 25 – 50% depending on building type and condition. These reductions would be achieved through a combination of envelope upgrades and other efficiency measures, some of which included fuel switching from gas to electricity. For comparison, under base case assumptions the Creative Energy Fuel Switch would reduce GHG emissions by 75% across all building types.

The RDH study suggested capital costs ranging from $3 – 37 / m^2 in commercial buildings and $4 – 23 / m^2 in residential buildings, and suggests that total abatement costs would in many cases be negative (i.e. the savings from reduced energy use would make these upgrades economical without any additional value placed on GHG reductions). RDH's analysis assumes that these retrofits would be in addition to a larger building upgrade project, so their cost estimates reflect the incremental cost to reduce GHG emissions in buildings which are already undergoing significant renovations. The range of capital costs reflects both different levels of upgrades as well as uncertainty in underlying capital costs for each type of upgrade. Not all buildings would be able to achieve the maximum reduction targets, and the cost to retrofit buildings which are not otherwise in need of renovations would be higher. The RDH study argued that building owners would still require a financial incentive to overcome market barriers to achieving emissions reductions, and targeted an offset payment equal to 15% of capital costs (even for those projects which appear to have a negative carbon abatement cost). This works out to an offset cost of $30 - $70 per tonne depending on building type.

While this proposed program could achieve significant reductions, it is not directly comparable to the Fuel Switch because it cannot be applied to all types of buildings: it would need to target buildings which are already undertaking significant renovations.

A recent project in Vancouver provides a final reference point for building energy retrofits. The

80 Rocky Mountain Institute, "Retrofit Depot: Guide to Building the Case for Deep Energy Retrofits," September 2012, p 13. All units converted to metric.

81 Offset Opportunities for Buildings. Report can be found at: http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/offset-project-development-opportunities/offset_opportunities_for_buildings.pdf

▲ *The Belmont, a residential strata in Vancouver, recently underwent a deep energy retrofit.*

owners of The Belmont, a residential strata, recently decided to pursue deep energy retrofits as part of a larger retrofit project completed in 2012.[82] The building is heated by a gas-fired common ventilation system, with in-suite electric baseboards as well as some gas fireplaces and a gas-fired DHW service. The retrofit was primarily aimed at reducing in-suite electricity consumption for heating. The project included metering of actual savings after the retrofit was complete. The building's energy usage was significantly reduced, with a total reduction in site energy of 43 kWh / m^2 / year, at a negligible incremental capital cost relative to the original retrofit scope, suggesting a low or even negative carbon abatement cost.[83] However, the building had poor energy performance to begin with, so this reduction was from a very high baseline. After the retrofit, the total heating energy use intensity was sill approximately 135 kWh / m^2/ year, which is higher than the system-wide average energy use intensity for Creative Energy's existing steam customers.[84] While this building is a nice example of a cost-effective energy retrofits, it does not achieve anywhere near the emission reductions of the Fuel Switch. Most of the residential buildings served by the steam system are of a more recent vintage than The Belmont, and they are already better performing buildings.

Energy retrofits of existing buildings and the Fuel Switch are not mutually exclusive. However, energy retrofits alone will not achieve the level of GHG reductions possible with the Fuel Switch, and certainly nowhere near the cost of the Fuel Switch. Building retrofits will require decisions by dozens of different building owners and the optimal timing of such retrofits will vary depending on the nature and vintage of each building. The Fuel Switch has a minimum efficient scale. However, there is also substantial new development planned for downtown (and other existing gas-fired buildings not connected to district energy) that could use any capacity freed up over time as existing customers improve efficiencies.

82 Hanam, B et al, "Deep Energy Retrofits of High-Rise Multi-Unit Residential Buildings," RDH Engineering, 2014 ACEEE Summer Study on Energy Efficiency in Buildings, 1–109-120. As actual performance was within 1% of the modeled numbers, we have estimated the share of post-retrofit energy used for heating using Figure 7, and assuming 85% boiler efficiency.

83 Pape-Salmon, A. "Deep Energy Retrofit of the Belmont", RDH Building Engineering.

84 The system-wide average reflects a mix of residential and commercial buildings of different types. Office buildings have relatively lower heating requirements then residential buildings or hotels. For another comparison, the average heating energy intensity of new buildings in the City's SEFC NEU is also over 100 kWh/m^2.

10.6 SUMMARY

Figure 41 shows the levelized production costs of the different supply alternatives discussed above. The range of costs for the Fuel Switch reflects base case assumptions together with partial property tax relief and optimized interconnection costs (as discussed at the end of Section 9). Further optimizations and additional enabling strategies are still possible (and may be necessary to secure long-term contracts with existing customers). The cost of conventional gas-fired steam from the existing Beatty Street plant is also shown for reference. While the Fuel Switch is more expensive than conventional gas-fired steam (which gives rise to the financial gap discussed in this report), it is still the cheapest source of low-carbon energy for existing steam customers. It is also cheaper than a small sewer heat recovery plant serving only new customers in NEFC (which is also representative of the expected cost of smaller energy plants to serve new customers in other expansion areas of downtown such South Downtown). The Fuel Switch is even less costly than the next increment of heat pump capacity within the City's existing sewer heat plant in SEFC.

Figure 42 shows these same results from the perspective of implicit carbon abatement costs. Carbon abatement costs are calculated as the present value of the premium for each alternative relative to conventional gas-fired steam at Creative Energy's existing plant (under base case forecast of gas prices before carbon taxes) divided by the present value of GHG reductions relative to Creative Energy's existing steam plant. The carbon abatement costs of various alternatives are calculated over a 30-year period in nominal dollars (i.e., including inflation) using Creative Energy's nominal after-tax weighted average cost of capital of 5.95%.[85] While the Fuel Switch has the lowest cost of carbon abatement of the alternatives considered, the forecast premium still exceeds existing carbon taxes and offset costs in B.C., even after including a recent federal proposal to establish a higher minimum national floor on carbon prices by 2022. At the same time, the carbon abatement cost of the Fuel Switch is well below the estimated marginal abatement costs from a variety of studies for Canada to achieve its GHG reduction targets for 2030 and 2050.[86] This illustrates the mismatch between long-term government targets and existing policies.

Figure 43 shows the results from the perspective of end users in the form of indicative levelized retail rates under various supply scenarios. Retail rates reflect the combined costs of different energy supply scenarios together with other service costs (e.g., network costs). Under base gas and carbon price projections (with no additional carbon policies), existing steam customers could expect to pay levelized retail rates of $80 / MWh or less for heat over 30 years starting in 2020. PSOs, which represent about 12% of Creative Energy's existing customer base, currently incur an additional cost of about $7 / MWh to offset their emissions from purchases of gas-fired steam. Under base fuel price forecasts and project cost assumptions (after some property tax relief and promising optimizations discussed at the end of Section 9), the Fuel Switch would increase retail rates for existing customers an average of 30 – 35% over 30 years starting in 2020 (a net increase in bills of only 15 – 20% for PSOs when also taking into account their avoided cost for offsets).[87] This is a theoretical rate impact assuming the full cost of service for the Fuel Switch (no further project optimizations, property tax rationalization or other enabling strategies) and an immediate 75% reduction in GHG emissions for all existing customers. Actual rate impacts for existing customers could be lowered through further project optimizations or enabling strategies as discussed in Section 9. Rate impacts for existing customers could also be reduced by lowering or phasing in the

85 This calculation shows the break-even carbon price from the perspective of the utility. Using Treasury Board guidance, which recommends discounting environmental benefits using a 3% rate, the absolute carbon abatement cost is much lower. But this lower discount rate does not affect the relative ranking of projects.

86 See e.g. Bataille, C. et al. (2015) "Pathways to deep decarbonization in Canada," SDSN – IDDRI.

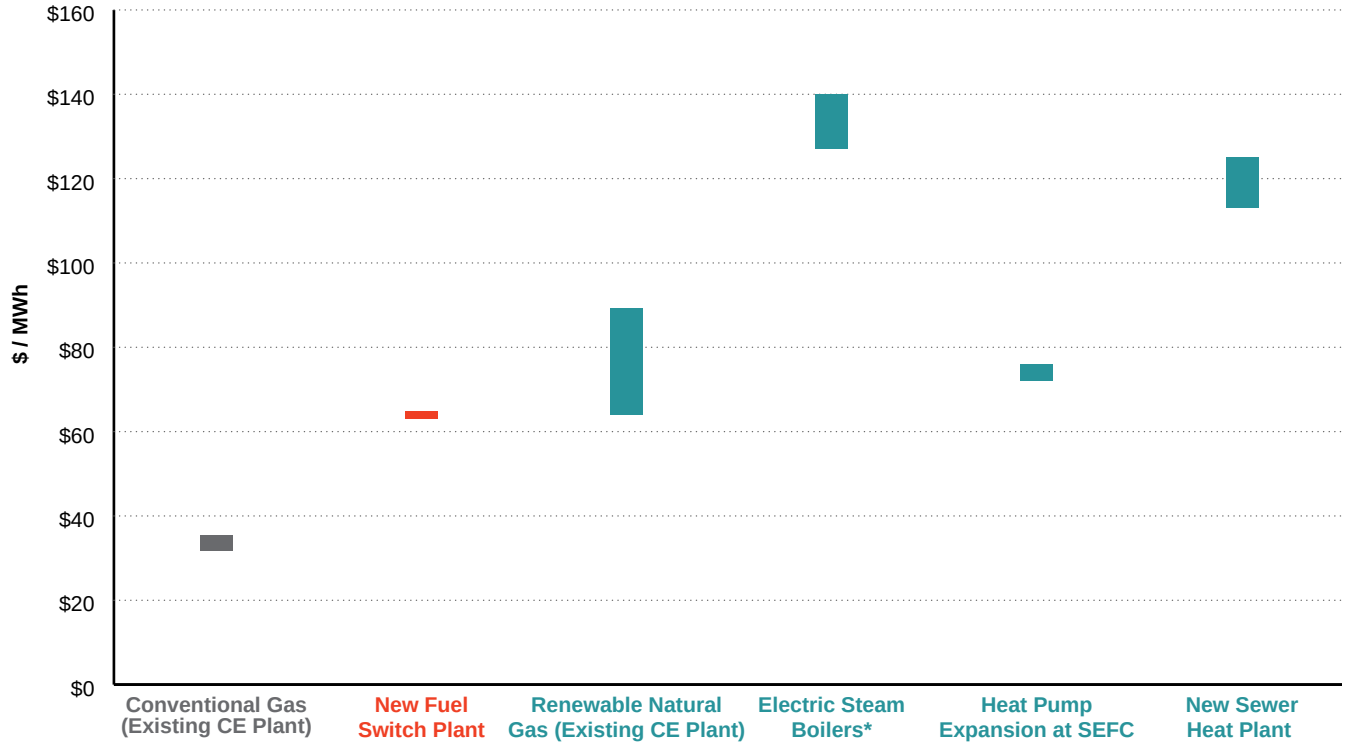
87 These are average (levelized) rate impacts over 30 years. In reality, the magnitude of rate impacts is higher in early years and declines over the analysis period. The feasibility study, which commenced three years ago, assumes a target in-service date of 2020. Given ongoing discussions with the City and senior levels of government, a more likely in-service date is now 2021.

GHG reductions (and associated project costs) allocated to existing customers. However, this would also require Creative Energy to secure other customers for the remaining output of the Fuel Switch energy and/or GHG reduction credits. Figure 43 also shows the indicative rates (under full cost of service) for existing steam customers under only a 30% reduction in GHG emissions.

The rates for NEFC include the incremental costs of a new hot water network as well as other directly allocated costs of service for the neighbourhood. Under formal carbon performance requirements for new development, customers in NEFC would be better off with the Fuel Switch compared to a local sewer heat plant. But the Fuel Switch would also require a larger customer base (i.e., core customers and other expansion areas).

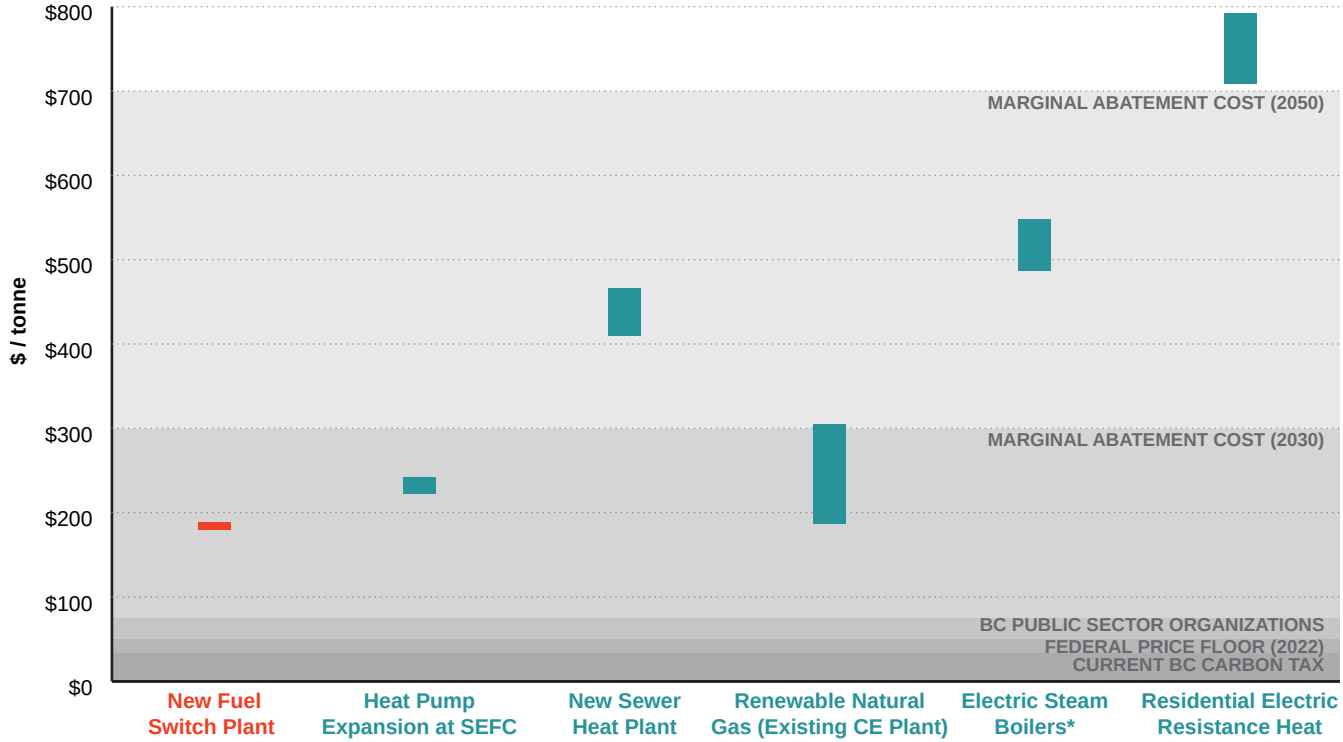
Finally, Figure 43 compares the indicative levelized rates for both existing steam customers and new hot water customers in NEFC under various scenarios to other retail rate benchmarks (also levelized) for low-carbon energy. These include SEFC, residential electric resistance heat (a common benchmark used by the City and the Commission for evaluating low-carbon thermal energy systems) and some recent low-carbon Stream A (on-site) thermal energy systems approved by the Commission. The on-site systems reflect a range of technologies including geoexchange and waste heat recovery. It is important to note that the expected carbon performance of these systems varies (and has not been confirmed in long-term operation) and in some cases the carbon performance is less than the proposed Fuel Switch. Many of these systems are also site-specific and not applicable to all building types or locations. Some of the retail rates for these systems do not reflect the full installed costs of technologies due to offsetting developer contributions. As shown in Figure 43, the retail rate for the Fuel Switch is very competitive with other low-carbon retail benchmarks. However, these benchmarks are also not relevant for existing customers with no formal carbon performance requirements.

Figure 41: *Levelized Production Costs of Alternatives**



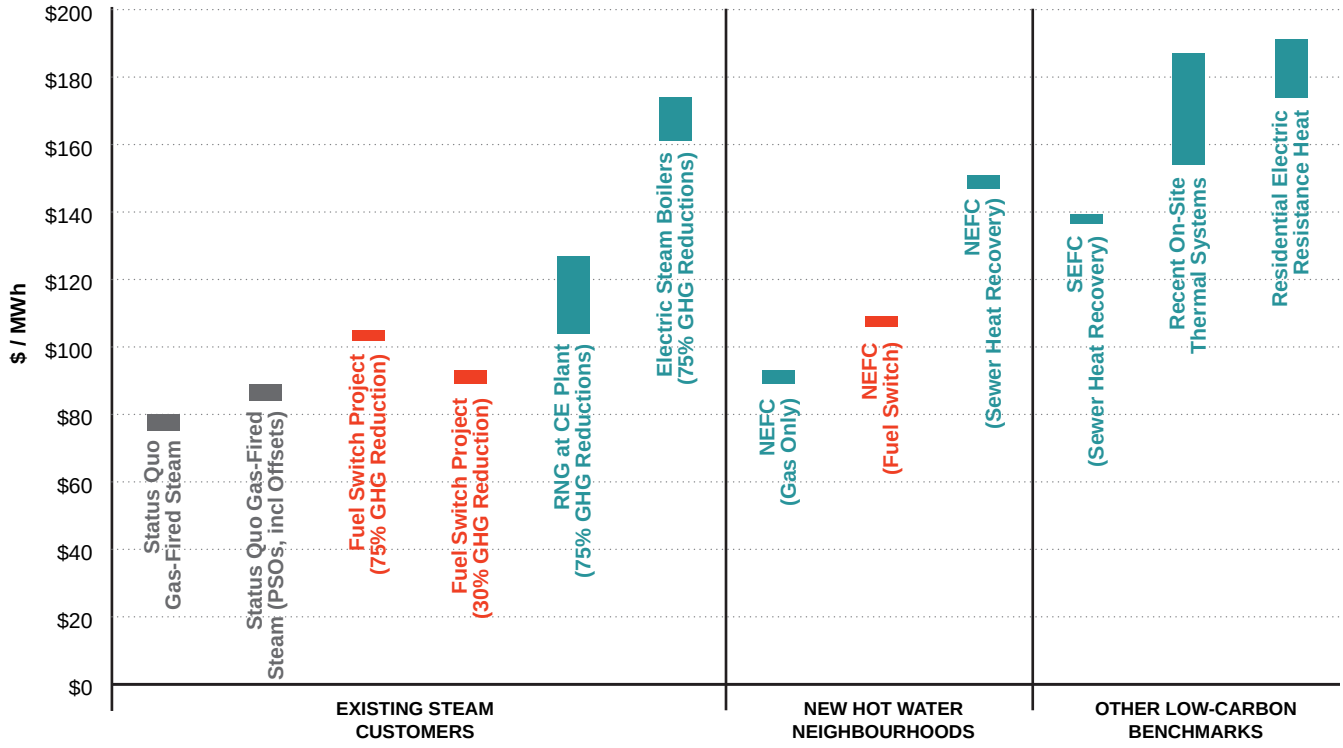
** Base case assumptions for Fuel Switch before further project optimizations or enabling tools. Electric steam boiler alternative reflects only variable cost of electric fuel and no additional capital cost for boilers, new plant, interconnection or upgrades to electric supply to plant.*

Figure 42: *Levelized Carbon Abatement Costs of Alternatives**



** Base case assumptions for Fuel Switch before further project optimizations or enabling tools. Abatement costs reflect level of carbon tax required to achieve zero NPV (break-even) relative to natural gas price forecast (low) under utility WACC. Using a 3% discount rate for the GHG reduction benefits (per Treasury Board Guidance), the ranking of options does not change but the absolute value of GHG reductions is substantially lower. A $150 million gap is equivalent to $160 / tonne under the utility WACC but only $113 / tonne under the Treasury Board rate of 3% for environmental benefits.*

Figure 43: *Levelized Production Costs of Alternatives**



** Projected levelized rates starting in 2020 for a period of 30 years under base case assumptions for Fuel Switch before further project optimizations or enabling tools.*

11. AIR QUALITY ASSESSMENT

As part of this feasibility study, Levelton Consultants (subsequently acquired by WSP) completed a preliminary air quality assessment. This section provides only a summary of the assessment. A full report is provided under a separate cover.

The key objectives for this assessment were to:

- confirm that building and stack height used in the plant design is appropriate from an air quality management perspective,
- estimate possible changes in ambient concentrations of air contaminants from the proposed plant, and
- compare the potential changes in ambient concentrations of air contaminants relative to current background concentrations and to Ambient Air Quality Objectives (AAQOs).

The assessment employed methods that are consistent with the *Guidelines for Air Quality Dispersion Modelling in British Columbia*. These methods are also consistent with the requirements of Metro Vancouver, which regulates air quality and air emissions in the region. The assessment predicts the incremental impact of emissions from the Fuel Switch on ambient air quality relative to baseline conditions and AAQOs, taking into account local meteorology.

The emissions considered in the preliminary air quality assessment are:

- particulate matter (PM),
- nitrogen oxides (NO_x),
- carbon monoxide (CO),
- sulphur dioxide (SO_2), and
- volatile organic compounds (VOCs).

In the presence of sunlight, NO_x and VOCs form ground-level ozone. Ozone and fine PM are the main components of what is commonly known as smog. With respect to PM, the main focus is $PM_{2.5}$ (fine PM less than 2.5 microns in diameter).

Plant emissions reflect the target sizing and preliminary design specification for the Fuel Switch project. It is typical in discussions around air quality impacts to express potential emissions in two scenarios:

1. **Expected Emissions Scenario:** This scenario uses expected plant emissions under normal operations based on actual operating data from equipment vendors and operators. These are typically lower than regulated limits.
2. **Regulated Emissions Scenario:** This scenario uses the maximum regulated emission limits in Metro Vancouver's Boilers and Process Heaters Emission Regulation Amending Bylaw No. 1190, 2013. These regulated limits are higher than what would be expected on average under normal plant operation.

Table 44 summarizes the direct annual emissions from the Fuel Switch plant under each emissions scenario, together with the net change in total emissions to the airshed taking into account a reduction in emissions from the existing Beatty Street plant, which would be displaced in part from the Fuel Switch. Net emissions for $PM_{2.5}$, CO, and NO_x are shown as these are the air contaminants from the plant that are of primary concern. Other air contaminants (SO_x and VOCs) were considered as part of the assessment and determined to be secondary. Details on these secondary air contaminants are provided in the detailed report.

Table 44: *Change in Annual Emissions from the Fuel Switch Project*

			EXPECTED EMISSIONS		REGULATED EMISSION LIMITS***	
Contaminant	**Existing Emissions from Beatty Street Plant***	**Expected Emission Reductions at Beatty Street Plant**	**Fuel Switch Plant**	**Net Change in Emissions to Air Shed****	**Fuel Switch Plant**	**Net Change in Emissions to Air Shed****
	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]
$PM_{2.5}$	0.3	0.2	14.9	+14.7	24.9	+24.7
NO_x	200	130	99.4	-30.6	199	+69
CO	64	42	149	+108	249	+207

** Based on 2013 National Pollution Release Inventory (NPRI) data reported by Creative Energy for the Beatty Street plant. Data reported to NPRI is based on permit levels for plant and run hours of equipment.*
*** Reflects net change in total emissions from the combined effect of adding the Fuel Switch plant together with reducing the utilization of the existing Beatty Street plant.*
**** This scenario reflects annual emissions if the plant operated continuously at regulated maximum levels.*

Table 45: *Emissions from Fuel Delivery Trucks*

	EXPECTED			REGULATED		
Contaminant	**Green House Emissions**	**Fuel Delivery Truck Emissions ***	**Total**	**Green House Emissions**	**Fuel Delivery Truck Emissions ***	**Total**
	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]	[tonnes/yr]
$PM_{2.5}$	14.9	0.09	15.0	24.9	0.09	25.0
NO_x	99.4	1.86	99.6	199	1.86	201

** Assumes 100km/trip for a WB20 style trailer (18m long) hauled by a diesel truck. Emissions factors per EPA's Motor Vehicle Emission Simulator (MOVES) which can be found at www3.epa.gov/otaq/models/moves/.*

The expected emissions scenario is nearly half of the regulated limits scenario. Under the expected emissions scenario there is a net reduction in NO_x emissions to the airshed. However, the reduction in emissions from the existing Beatty Street plant was not taken into account in the air dispersion modelling, which introduces an added conservatism to the air quality assessment.

The emissions of air contaminants from fuel delivery were not considered in the preliminary air quality assessment. A side analysis was prepared for the incremental PM and NO_x emissions associated with the truck delivery of fuel. The analysis is summarized in Table 45. The analysis shows that the incremental emissions from truck delivery of fuel are small. This analysis is also conservative because it assumes that 100% of these emissions would be incremental to the Fuel Switch project. In reality, there would likely be comparable or higher emissions associated with alternative disposal methods for wood waste in the region.

Table 46 and Table 47 show the net expected annual emissions of $PM_{2.5}$ and NO_x from the proposed Fuel Switch project (i.e., net of reductions at the existing Beatty Street plant) relative to other existing major point sources in the region, based on Metro Vancouver's 2010 Emissions Inventory.[88]

88 An updated inventory for 2015 is not expected to be released until later this year.

Table 46: Largest Point Sources of $PM_{2.5}$ in Metro Vancouver (2010 Inventory)

	POINT SOURCE	LOCATION	$PM_{2.5}$ [t/yr]
1	Kruger Products Limited Partnership	New Westminster	73.2
2	Fibreco Export Inc.	North Vancouver District	71.6
3	Richmond Plywood Corporation Ltd.	Richmond	53.6
4	Tree Island Industries Ltd.	Richmond	43.0
5	West Coast Reduction Ltd.	Vancouver	37.4
6	Chevron Canada Limited	Burnaby	35.4
7	Lehigh Cement, a division of Lehigh Hanson Materials Limited	Delta	32.5
8	Council Of Forest Industries	Kent	32.4
9	Gillwood Remanufacturing Inc.	Chilliwack	30.0
10	PTPC Corrugated Company	Richmond	26.4
11	PTPC Corrugated Company (Boxmaster)	Burnaby	17.0
12	Norampac Inc., Richmond Division	Richmond	14.9
13	**Creative Energy Fuel Switch (Hypothetical)**	**Vancouver**	**14.7**
14	Stella Jones Inc.	New Westminster	14.7
15	Esco Limited	Port Coquitlam	14.2
16	Swiss Water Decaffeinated Coffee Company Inc.	Burnaby	14.1
17	Ewos Canada Ltd.	Surrey	13.9
18	Lafarge Canada Inc.	Richmond	13.1
19	Bekaert Canada Ltd.	Surrey	13.0
20	Teal-Jones Group Ltd.	Surrey	12.4

Table 47: Largest Point Sources of NO_x in Metro Vancouver (2010 Inventory)

	POINT SOURCE	LOCATION	NO_x [t/yr]
1	Lehigh Cement	Delta	1,707.0
2	Lafarge Canada Inc.	Richmond	1,039.8
3	Chevron Canada Limited	Burnaby	265.1
4	**Creative Energy (Existing Beatty Street Plant)**	**Vancouver**	**196.4**
5	**Creative Energy (After Fuel Switch, Both Plants Combined)***	**Vancouver**	**169.4**
6	Canexus Chemicals Canada Limited Partnership	North Vancouver District	151.3
7	Kruger Products Limited Partnership	New Westminster	88.0
8	Richmond Plywood Corporation Ltd.	Richmond	38.6
9	Rogers Sugar Ltd.	Vancouver	37.2

** Direct NO_x emissions from the Fuel Switch would be offset by larger reductions in NO_x emission from the existing plant.*

Point sources are only a small portion of total emissions in the airshed, which include many area-based sources (e.g., transportation, including activities in the Port lands). Table 48 shows the incremental $PM_{2.5}$ emissions from the Fuel Switch relative to sector emissions. The project would increase total $PM_{2.5}$ emissions 0.3% in the region as a whole and 2.3% in the City of Vancouver. At peak output, the expected emissions of $PM_{2.5}$ from the Fuel Switch plant would be equivalent to about 100 residential fireplaces or 14 bulk carrier vessels at berth using diesel power.[89]

89 Fireplace emissions on convention residential fireplaces, with glass doors and without inserts (Table 4: http://www.bcairquality.ca/reports/pdfs/wood_emissions.pdf). Emission from bulk carriers are from WSP using data compiled for another client. Equivalency based on required power generation from diesel generations while ships at berth.

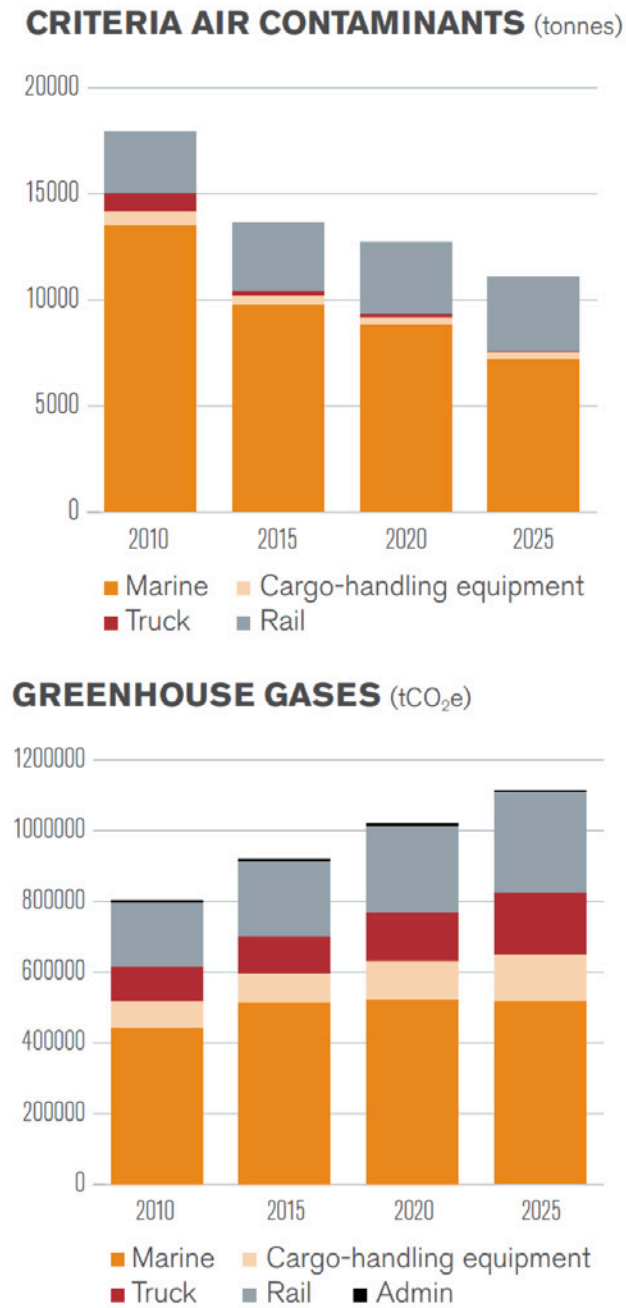
Table 48: *Incremental $PM_{2.5}$ Emissions from the Fuel Switch as a Share of Other Sources*

	ANNUAL $PM_{2.5}$ [tonnes/yr]	% INCREASE FROM FUEL SWITCH PROJECT
Fuel Switch	14.7	
Metro Vancouver, All	4,731	0.3%
Metro Vancouver, Industrial Only	1,055	1.4%
Metro Vancouver, Heating Only	1,339	1.1%
Metro Vancouver, On-Road Only	478	3.1%
City of Vancouver, All	663	2.3%

The Fuel Switch project must also be considered in the context of the trends in other sources of emissions. For example, the activities within the Port are one of the largest sources of Criteria Air Contaminants (e.g., PM, NO_x, and VOCs) in downtown Vancouver. The emissions of Criteria Air Contaminants from all activities within the Port have been declining in recent years and are projected to decline further, largely as a result of ongoing electrification of Port activities and replacement of older diesel engines in various activities (Figure 44). The incremental $PM_{2.5}$ from the Fuel Switch is equivalent to about 0.1% of all Criteria Air Contaminants expected to be emitted throughout the region by Port activities in 2020. In contrast to the trends in Criteria Air Contaminants, GHG emissions from Port activities are set to increase 200,000 tonnes over 2010 levels by 2020. For comparison, Phase 1 of the Fuel Switch project would lower GHG emissions by about 80,000 tonnes.

The net change in emissions from the project are only one consideration in the preliminary air quality assessment. The impact of these emissions on local air quality depends on dispersion (meteorology) and baseline conditions (and trends). The predicted impact of the project on ambient concentrations of air contaminants under each emission scenario was also assessed. This preliminary air dispersion model is conservative (pessimistic) because it does not take into account the reduced emissions from the existing Beatty Street plant. The impact on ambient concentrations was compared to background concentrations (under conservative assumptions) and also Metro Vancouver's AAQOs for $PM_{2.5}$, NO_2, CO, and SO_2.

Figure 44: *Trends in Criteria Air Contaminants vs. GHG Emissions from Activities in Port Metro Vancouver**



** Figure from Port Metro Vancouver Sustainability Report 2014. Data derived from Port Metro Vancouver's 2010 Landside Emissions Inventory and Environment Canada's Marine Emissions Inventory.*

AAQOs are used as a comparator for regulators to ensure long term protection of public health and the environment. The AAQOs are non-statutory limits (i.e. not legally binding) and are used to:

- gauge current and historical air quality,
- guide decisions on environmental impact assessments and authorizations,
- guide airshed planning efforts,
- inform regulatory development, and
- develop and apply episode management strategies such as air quality advisories.

AAQOs are set for each contaminant over several different averaging periods. AAQOs for short-term exposure (measured as maximum 1hr, 8hr, or 24hr averages, depending on the contaminant) are generally higher than AAQOs for long-term exposures (annual average). The short-term and long-term AAQOs are based on consideration of acute and chronic health impacts.

Background concentrations of $PM_{2.5}$, NO_2, CO and SO_2 were estimated using data from Metro Vancouver's Kitsilano and Robson Air Quality Monitoring Stations. These are the closest monitoring stations to the proposed Fuel Switch site (approximately 5 km and 2 km from the site). The air dispersion model predicted potential (conservative) impacts at several locations including the fence line of the plant, the nearest residential receptor (corner of Great Northern Way and Thornton Street), and the site of the new St. Paul's Hospital.

Detailed results are provided in the final report for the Air Quality Screening Assessment prepared by WSP. Some key observations and conclusions from this report are as follows.

- The Fuel Switch plant is expected to be able to meet or exceed Metro Vancouver's requirements under both expected and regulated scenarios.
- Small exceedances were predicted for some short-term AAQOs under very conservative assumptions (regulated emissions scenario, no consideration of emission reductions from existing plant, no additional mitigation measures, conservative meteorological and ambient air quality conditions). These exceedances were very infrequent (several hours of the year). They also occurred very close to the plant, reflecting downwash effects, which will also depend on the final design of the buildings and the stack height. For example, the model predicted exceedance of the 24-hour $PM_{2.5}$ AAQO for only 1 hour out of the 8,784 hours and only at the plant fence line.
- A more refined dispersion model will be required during the formal permitting process.

Although air quality impacts are very small and highly localized, there are additional mitigation options including changes in plant design and external offset projects (in particular projects to reduce other existing sources of $PM_{2.5}$).

12. CONTRIBUTION TO B.C. ENERGY OBJECTIVES

Under the Commission CPCN Guidelines, proponents must demonstrate how a project contributes to British Columbia's energy objectives in the Clean Energy Act. Table 49 summarizes the potential contribution of Creative Energy's Fuel Switch project to each of the objectives in the Clean Energy Act.

Table 49: *Contribution of Fuel Switch to B.C.'s Energy Objectives*

B.C. ENERGY OBJECTIVE	CONTRIBUTION OF CREATIVE ENERGY FUEL SWITCH
(a) to achieve electricity self-sufficiency;	The project reduces new demands for electricity for heating purposes (in new development areas served by the project as well as near-term expansion of sewer heat recovery plant at SEFC).
(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;	See above.
(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;	Possibility to add green electricity production to the Fuel Switch project. Green energy generation in the Lower Mainland reduces pressure on long-distance transmission infrastructure (and provides local reliability benefits).
(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;	Fuel Switch is based on local wood waste.
(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the BC Hydro Public Power Legacy and Heritage Contract Act continue to accrue to the authority's ratepayers;	N/A
(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;	The project reduces pressure on transmission and distribution systems and need for new green electricity supply.
(g) to reduce BC greenhouse gas emissions (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;	Fuel Switch makes a substantial contribution to GHG reductions (equivalent to 16,500 cars or 11% of public sector offset purchases).
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;	This is the central purpose of the Creative Energy Fuel Switch.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;	The Fuel Switch is consistent with City policies to achieve these outcomes.

B.C. ENERGY OBJECTIVE	CONTRIBUTION OF CREATIVE ENERGY FUEL SWITCH
(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;	The Fuel Switch represents an efficient use of local urban wood waste (higher efficiency than stand-alone electric plants fired with biomass). Thermal networks provide opportunities for greater waste heat recovery.
(k) to encourage economic development and the creation and retention of jobs;	The Fuel Switch will create 50+ direct and indirect jobs, including upstream investment / jobs in enhanced waste recovery, processing and delivery, as well as direct and downstream jobs associated with the rooftop farm.
(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;	First nations and rural communities could play a role on upstream waste recovery and processing.
(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;	N/A
(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;	The Fuel Switch frees up green electricity for export and also provides a potential new source of green electricity.
(o) to achieve British Columbia's energy objectives without the use of nuclear power;	See above.
(p) to ensure the commission, under the Utilities Commission Act, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.	N/A

13. PRELIMINARY STAKEHOLDER CONSULTATIONS

The feasibility study has been informed both by preliminary consultations as part of this study, as well as information from other relevant consultation processes conducted by the City. Consultation will be required to finalize the project design, prepare all relevant permit applications (e.g., air quality permit, development permit and building permit), and prepare a CPCN application to the BCUC. This will need to include additional consultations with customers (to establish long-term contract commitments for the project) and other community stakeholders (to discuss other broader community impacts and benefits).

13.1 INDUSTRY AND AGENCY CONSULTATIONS

The City was consulted throughout the study via a staff-level working group and a steering committee composed of senior management. The study team also met on one occasion with BCUC staff to provide an interim update on the study and framing for the project. During the site selection process there were meetings with real estate brokers and some specific organizations and landowners related to the site. These included Port Metro Vancouver, Rogers Sugar, and Washington Marine Group. The Climate Investment Branch (formerly Pacific Carbon Trust) was consulted on provincial offset opportunities, and the team submitted a Project Information Document (PID) to the Climate Investment Branch as a first step in the process of selling offsets, if that proves to be an acceptable strategy for customers and the City to reduce any outstanding financial gap for the project.[90]

Fuel suppliers and technology vendors were consulted as part of this study through the RFIs, together with follow-up interviews and discussions. The BC Bioenergy Network was consulted in creating the list of potential technology vendors and fuel providers. The study team also consulted Metro Vancouver's Environmental Regulation and Enforcement Division to confirm the team's understanding of existing air quality regulations and permitting requirements, and to make them aware of the project.

During the feasibility study there were also meetings about the project with specific customers as part of other planning processes or discussions, including Canada Place, Vancouver Convention Centre, and St. Paul's Hospital. As noted elsewhere in this report, St. Paul's is a large existing steam customer and there is still some uncertainty over its specific plans to relocate to a site on the False Creek Flats where considerable synergies with the Fuel Switch would be possible.

Canada Place, operated by the Port (federal agency), is not an existing customer of Creative Energy but the facility is adjacent to the existing Creative Energy network and has a significant steam load served from an aging on-site gas-fired steam plant.

The bulk of this feasibility study was completed by December 2015. For the past year, Creative Energy has continued to monitor project drivers and assumptions, while continuing to engage the City, the Province and the federal government in discussions about project barriers and enabling strategies. In parallel to discussions

90 To qualify as offsets, the GHG reductions must be considered additional. This rules out GHG reductions associated with mandatory connections. For other customers with no mandatory reduction requirements, it may be possible to reduce the premium they pay for the project through the sale of offsets for some time period. In this case, customers would have no legal claim to the GHG reductions for the period they are sold, but could claim other benefits from green energy purchases, as well as retain the benefit of future GHG reductions after the period for which offsets are sold. In the case of Public Service Organizations, GHG reductions would not be sold as offsets but rather retained by these customers in lieu of the requirement to purchase offsets.

with government, the study team has provided high level briefings on the project to nearly 50 individuals and organizations. These have included local landowners near the proposed plant site, individual property developers downtown, existing or potential customers (e.g., St. Paul's and Canada Place), the Chief Medical Health Officer for Vancouver Coastal Health, Metro Vancouver, other thermal energy utilities, local architects, local mechanical engineers, and a number of community and professional associations (e.g., Conversations for Responsible Economic Development, Urban Development Institute, Fraser Basin Council, Vancouver Economic Commission, International Building Performance Simulation Association). The purpose of these preliminary briefings was to test assumptions, seek new ideas, explore issues, and create a foundation for future conversations. Participants in these briefings expressed interest in the project and the initial response to the project has been overwhelmingly positive. They have raised good questions, confirmed key issues and provided invaluable input and ideas to consider in future design, communication and implementation of the project. These stakeholders have generally understood the market challenges for the project and the need for enabling strategies. Some have provided feedback on specific enabling strategies considered in this study and all have expressed interest in receiving on-going updates about the status of the project.

13.2 IN-DEPTH STAKEHOLDER INTERVIEWS

In addition to the discussions and meetings above, the team also engaged Ipsos Public Affairs to conduct individual in-depth interviews as part of the formal workplan for the feasibility study. Three key stakeholder groups were considered in this research:

1. Existing Creative Energy customers (mainly operations or energy managers).

2. Potential customers, including property managers and developers.

3. Other involved stakeholders, including architects, consulting engineers and non-profit foundations.

Creative Energy provided representative contacts for each stakeholder group. Ipsos Public Affairs was responsible for securing actual interviews.

In-depth interviews allow a skilled interviewer to establish a facilitative atmosphere that is relaxed, conversational, and encourages free-ranging responses. By allowing for detailed probing on key issues, in-depth interviews provide a rich understanding of respondents' views and opinions. They are often conducted with elite or hard to reach audiences and those that might not work in a focus group setting. A discussion guide was prepared for the interview process.

The in-depth interviews were conducted from September 30 to October 21, 2015. A total of 24 interviews were conducted with stakeholders. The distribution of the interviews was 8 current customers, 5 potential customers and 11 other stakeholders. The other stakeholders comprised six representatives from non-profit organizations to represent broad community interests, as well as architects and engineers who often support building decision makers. Ipsos provided a summary report of findings. Individual interviews were kept confidential and specific comments are not attributed to specific interviewees. As with all qualitative projects, these findings are considered exploratory in nature and cannot be extrapolated to the overall population.

Awareness of Creative Energy was high among the existing customers, potential customers and other stakeholders included in this research, as is awareness that the company used to be Central Heat. Attitudes toward Creative Energy were generally positive among customers, but not enthusiastic. Rates were identified as an important issue, and some customers already perceive them to be too high.

Many stakeholders were not that knowledgeable when it comes to Creative Energy's future plans, and many stated that they would like hear more from Creative Energy. These stakeholders would like detailed information that demonstrates the efficiency of the existing plant and future operations, end-to-end accounting of energy use and GHG emissions, and more information on the

Fuel Switch project. They also commented that the public needs education so that they will be more likely to support low-carbon projects.

Around six-in-ten of the participants agreed that district energy is in the public interest, with the remainder saying 'it depends' or disagreeing. The most important benefits of district energy identified by participants were energy efficiency and environmental impact. Participants did note the high reliability of the existing system and benefits of eliminating on-site equipment. But there was also concern about the efficiency and carbon emissions without new forms of energy supply. The greatest concern raised was cost, particularly among developers of new buildings who expressed concerns with costs for connecting their development to district energy but also questioned consumer willingness to pay more for low-carbon energy.

There was a great deal of uncertainty expressed about what the energy cost will be for future projects, and this is an important issue for potential customers. Explaining how rates are set does not mitigate this concern, since potential customers still do not know what the cost will be. And some participants point to other district energy systems where they believe the energy cost is higher for the end-users.

Despite general concerns about energy costs, nearly all of the participants in the in-depth interviews stated an interest in green energy and that they would be willing to pay more for green energy. Many state that they would be willing to pay 10 to 20% more for green energy, with some stating that they are willing to pay even more than this. However, statements about willingness to pay would still need to be confirmed through actual signed contracts with customers. Customers also differed in opinions about whether green energy should be mandated and consistent across all customers, or whether each customer should be allowed to set its own amount of green energy purchases based on their unique circumstances and the price.

Nearly all stakeholders agree that municipalities such as the City of Vancouver should support district energy projects. They believe that municipalities should take a leadership role to facilitate adoption of more environmentally-friendly energy systems. There is not as much agreement when it comes to the specific actions that a municipality should take.

Participants were asked whether they would support each of the following potential types of municipal involvement:

1. *Require new or existing buildings to connect to low-carbon district utilities*
2. *Require new buildings to meet carbon reduction targets by either connecting to a low-carbon system or developing an on-site alternative*
3. *Property tax reductions for district energy plants that generate alternative energy*
4. *Property tax reductions for buildings that utilize district energy plants*
5. *Grants for low-carbon projects*
6. *Land or other support for developing neighbourhood-scale low-carbon projects*
7. *Financing for low-carbon projects*
8. *Partnering in development and delivery of low-carbon systems*

The majority of participants said that they would support these actions. The second and third alternatives (carbon reduction targets for new buildings and property tax reductions for district energy plants that generate alternative energy) drew the strongest level of support. Support for the first option may have been higher; however several participants would support it only for new buildings, if existing buildings were not required to retrofit. While there is some support for these options, in many cases it is conditional, or represented very initial reactions to ideas that respondents may not have previously considered. Both willingness to pay for green energy and willingness to support policy tools will ultimately depend upon the specifics of the project.

13.3 BROADER CITY CONSULTATIONS

Some of the consultation activities of the City that have influenced this study include consultations related to:

- the Greenest City Action Plan (GCAP),
- Vancouver Neighbourhood Energy Strategy and Vancouver Energy Centre Guidelines,
- current False Creek Flats Planning Process,
- Northeast False Creek Community Planning Processes, and
- Renewable Cities Strategy.

The recent False Creek Flats planning process has included specific discussion and feedback on the possible role of this kind of project in the future plans for the Flats.

The City undertook an extensive consultation process for the GCAP.[91] Over 35,000 community members participated in the process, with 9,500 actively contributing to determine the "best path forward", which included initiatives to establish new neighbourhood energy systems and convert existing steam heat systems to low-carbon energy sources. Timing of this process was as follows:

Phase 1 ran from June - October 2010 and was focused on collecting ideas from the community about how the Greenest City goals and targets might be achieved.

Phase 2 ran from December 2010 - March 2011 and was focused on collecting feedback on the draft Greenest City Action Plan in order to finalize the plans.

The development of the Vancouver Neighbourhood Energy Strategy included two separate streams of stakeholder consultation:[92]

A. to get input on the overall strategic approach for establishing systems; and

B. to get input on the development of the Vancouver Energy Centre Guidelines, which establish the performance requirements for development and operations of new low-carbon energy generating facilities in the city.

For item A above, the City hosted workshops in December 2011 and May 2012 with stakeholders to get input on scope, objectives, issues, barriers and opportunities to be considered by the strategy. The stakeholders in Table 50 participated in these workshops.

Table 51 provides a list of stakeholders that were included in the development of the Energy Centre Guidelines (item B above). The consultations for the Energy Centre Guidelines involved a more in-depth process and specific individuals were selected from each organization to meet on several occasions. These stakeholders were selected based on demonstrated interest and/or expertise in fields that relate to climate protection, air quality, resource use sustainability and the utility industry. Stakeholders also included residents who have actively participated in past public engagement processes for neighbourhood energy projects or related policy.

In November 2015, the City released its Renewable City Strategy, with targets to derive 100% of the energy used in Vancouver from renewable sources before 2050 and to reduce GHG emissions by at least 80% below 2007 levels before 2050. The Renewable City Strategy was informed by a Renewable City Action Team along with a variety of external stakeholders and advisors. The Fuel Switch was identified as one of the priorities in the Renewable City Strategy. However, there was no specific consultation, discussion or feedback from the Renewable City Action Team regarding the results or issues raised in this study.

91 For more information on the Greenest City Action Plan and related consultation processes, please go to http://vancouver.ca/files/cov/GCAP-council-report.pdf

92 Detailed information on the Vancouver Neighbourhood Energy Strategy and related consultation processes is available at: http://former.vancouver.ca/ctyclerk/cclerk/20121003/documents/ptec1.pdf

Table 50: *List of Workshop Stakeholders*

UTILITIES	DEVELOPER / LAND OWNER / CUSTOMER	GOVERNMENT / INSTITUTIONS / NGOS
Creative Energy	Urban Development Institute	Metro Vancouver
BC Hydro	Urban Land Institute	City of North Vancouver
FortisBC	Bentall	City of Richmond
Corix	Westbank	Vancouver School Board
Cofely	Parklane	University of BC
Dalkia / Veolia	Building Owners and Managers Association	BC Climate Action Secretariat
	Condominium Owners Association	BC Housing
	Cadillac Fairview	Port Metro Vancouver
	Convention Centre	Natural Resources Canada
		Navius Research
		Community Energy Association

Table 51: *Stakeholders included in the Development of the Energy Centre Guidelines*

Environmental Non-Government Organizations	David Suzuki Foundation Pembina Institute Wilderness Committee
Government Agencies	Fraser Coastal Health Metro Vancouver Fraser Valley Regional District
Academia	University of B.C. University of Victoria
Utility Industry	Canadian District Energy Association BC Hydro River District Energy / Parklane
Residents of Neighbourhood Energy Areas	False Creek South False Creek East Cambie Corridor

14. IMPLEMENTATION ISSUES AND NEXT STEPS

The Creative Energy Fuel Switch is technically feasible. The proposed technology has many local and international precedents. The project supports aggressive GHG reduction targets established by the Government of Canada, the Province of B.C., and the City of Vancouver. It also supports other community objectives for resource recovery, energy resilience, food production, green jobs, and education. The project could serve as a model and inspiration for achieving deep GHG reductions and other community benefits in dense urban areas throughout Canada.[93]

The Fuel Switch represents one of the largest and most cost-effective sources of renewable energy and carbon reductions in Vancouver, even before further design optimizations. The low cost of the Fuel Switch is due in part to its economies of scale. But the project's size and lead time also pose implementation challenges under current market constraints, ongoing policy gaps, and recent regulatory decisions.

The direct capital cost of the Fuel Switch project is about $135 million.[94] For comparison, Creative Energy's current utility rate base (i.e., original capital cost less accumulated depreciation) is about $30 million. This reflects the age of existing assets, which remain in good condition, as well as the original cost of land for the existing steam plant (which is housed in a repurposed building). The replacement cost of the system today would be over $100 million (even before considering higher land costs today). The Fuel Switch plant is also a more capital intensive technology than a conventional gas-fired plant. In addition, the target size exceeds the energy requirements of existing Creative Energy customers, and the plant includes a rooftop farm.

The initial development and subsequent extensions of Creative Energy's steam system were secured with long-term customer contracts. However, most Creative Energy's existing customers were connected many years ago and are now on month-to-month contracts. A significant new investment such as the Fuel Switch will require new long-term contracts and/or other enabling strategies to offset the substantial investment risk.[95]

To that end, Creative Energy intends to run a voluntary subscription process to secure new long-term contracts with existing customers and other existing buildings downtown to support the Fuel Switch project. Creative Energy already serves buildings controlled by the federal government, the Province, and the City. There are many other government-controlled buildings downtown that are currently heated with natural gas but could also be connected to the Fuel Switch project. All levels of government have established formal targets and/or financial incentives to reduce carbon emissions in their operations and could, by committing to the Fuel Switch, demonstrate market leadership for commercial and residential customers. Preliminary market research and anecdotal evidence also suggests some interest in low-carbon heat among large commercial customers, whether to meet corporate commitments and tenant expectations (such as green building certification for existing buildings, which would be enabled by the project), or to reduce exposure to very uncertain and

93 Canada currently lags behind international best practices and experience with respect to thermal networks and low-carbon heating in dense urban areas. While the specific energy sources will vary over time and depending on the local context, the Creative Energy Fuel Switch could serve as an important precedent for fuel switching of legacy district energy systems, transitioning from legacy steam to modern hot water systems in mixed use environments, expanding thermal energy networks, designing and siting low-carbon energy projects with multiple community benefits in dense urban areas, and designing strategies to address near-term policy or market gaps hindering the long-term transition to a low-carbon economy.

94 This includes the additional cost of the rooftop farm to offset land costs and property taxes. The portion of capital costs allocated specifically to energy production is $121 million.

95 For comparison, developers of green power and renewable natural gas projects in B.C. rely on long-term contracts with BC Hydro or FortisBC, respectively. BC Hydro is financed by the Province and has an effective monopoly in retail electricity supply. The volume of RNG purchased by FortisBC is very small in relation to total sales. Further, the Commission has recently approved an application by FortisBC to recover any premium for unsold volumes of RNG from its larger base of conventional natural gas customers.

▲ *Creative Energy's existing plant on Beatty Street, adjacent to BC Place.*

volatile prices for conventional energy.[96] However, Creative Energy does not expect that a voluntary subscription process alone will yield sufficient contract volumes and/or price premiums to bridge the financial gap for existing customers of nearly $156 million under current gas and carbon price forecasts.

The Fuel Switch project was initially conceived to reduce emissions for current customers by over 75%. This is only an interim step towards Vancouver's long-term goal to be a 100% renewable city by 2050. Despite these aggressive targets, there are still no formal policies in place to require or support GHG emission reductions in existing buildings. While the Fuel Switch represents a cost-effective source of low-carbon energy, the levelized premium on existing customer bills over 30 years to achieve such deep GHG reductions under current gas and carbon prices could be over 40% in the absence of further optimizations or other enabling strategies. The existing steam plant is highly depreciated but in good condition. Recent gas price forecasts are near record lows. And current carbon prices are well below what models suggest will be required to achieve the reduction targets of all levels of government in Canada by 2030 or 2050.[97]

There is some possibility to phase the Fuel Switch project, but given significant economies of scale this would also increase the cost of carbon abatement from the project. And there is still a minimum effective size of the Fuel Switch given the need for a new site, new building, and long interconnection.

The Fuel Switch project is also time sensitive. Land is scarce. Today's low interest rates reduce the cost of capital-intensive projects, but they are not expected to last indefinitely. There are some large new developments and existing buildings facing near-term investment decisions, including a major new hospital campus. If potential customers are forced to pursue conventional systems or costlier low-carbon alternatives because of uncertainty or delays in the Fuel Switch project, this could reduce the ultimate number of customers available to commit to the Fuel Switch project. Finally, there could be cost savings from coordinating the Fuel Switch project with other near-term infrastructure projects downtown such as the removal of the viaducts in NEFC.

The feasibility study has identified a range of additional strategies to help secure the large initial

96 In the absence of formal policies or requirements, small commercial customers and residential stratas are likely to be more price sensitive, and there is added complexity due to collective decision making in residential strata buildings.

97 Even if reduction targets were achieved through other means besides carbon pricing, all models suggest the marginal abatement cost of such policies would still greatly exceed the carbon abatement cost of the Fuel Switch project.

investment in the Fuel Switch project. No single strategy alone will be sufficient. However, there are many viable combinations of strategies that could be used to secure this significant but time-sensitive legacy for Vancouver. The City has a key role to play in advancing the Fuel Switch project in all scenarios. However, there are also varying types and degrees of support required from other levels of government (Table 52). Some strategies involve policy updates. Others may require direct or indirect financial support. As a regulated utility, Creative Energy only earns a regulated rate of return based on its net investment in the project. Any financial support from the City or other levels of government would go directly to reducing customer rates and/or the gap between the project revenues and its regulated cost of service.

Table 52: *Key Roles for Different Levels of Government in the Creative Energy Fuel Switch*

	MINIMUM ROLE	ADDITIONAL SUPPORT OPPORTUNITIES
City	• Provide lease for target site* • Help secure design optimizations for interconnection • Rationalize property taxes • Commit City buildings to purchase low-carbon energy from the project • Acquire energy from the project for SEFC NEU • Develop policy frameworks to secure new development (establish clear and rational carbon performance standards, establish mechanisms to recognize future Fuel Switch energy or carbon credits within compliance options for early adopters, address conflicting policy requirements for early adopters)	• Own some assets to help secure grants or allow 100% debt financing • Clarify any future policies for existing buildings in order to support voluntary subscription process • Defer land rent, residual property taxes and/or payments for City-owned infrastructure based on future gas and carbon prices • Divert City-controlled sources of urban wood waste to Fuel Switch project
Province	• Commit provincial buildings to purchase low-carbon energy from the project	• Support federal grant applications • Purchase of offsets (dynamic pricing proposal) from unallocated carbon reductions from the Fuel Switch project to support carbon neutral government commitments • Develop new grant program(s) to support low-carbon heating networks and larger supply projects • Clarify long-term carbon prices or support programs for carbon reductions in existing buildings • Address property tax barriers for low-carbon thermal energy networks and supply projects • Support development of urban wood waste collection and processing infrastructure
Federal Government	• Commit federal buildings to purchase low-carbon energy	• Provide recoverable or non-recoverable grant(s) • Clarify long-term carbon prices or support for carbon reductions in existing buildings • Support development of urban wood waste collection and processing infrastructure

** The City-owned site on 425 Industrial Avenue is the only remaining viable site for this project. The site lease should also include an option on the neighbouring City-owned site to allow future expansion of low-carbon energy.*

Figure 45 depicts possible packages of strategies that would enable the Fuel Switch. These strategies are separated into Tier 1, Tier 2, and Tier 3. Details on the individual strategies are provided in Table 53 through Table 55. There are interactions among individual strategies. Table 53 depicts the incremental impact of each successive strategy after the effect of previous strategies. For example, sales to SEFC and government buildings are priced at the full cost of service for the project. The optimization of interconnection costs and rationalization of property taxes would reduce the cost of service for all users. If these do not occur, then sales to SEFC and government buildings would still cover their full cost of service and the absolute impact of these strategies on the larger financial gap would be slightly higher.

Tier 1 represents the easiest and most immediate strategies to reduce the financial gap. These strategies are common to all scenarios depicted in Figure 45. Most of the Tier 1 strategies are within the City's control, with the exception of commitments from other levels of government to purchase low-carbon energy from the project for their own buildings. Even the success of the voluntary subscription process is partly dependent on City leadership in the acquisition of low-carbon energy and in clarifying likely future carbon policies for existing buildings. Tier 1 strategies do not impose any direct financial burden on Vancouver tax payers.[98] Although voluntary subscriptions form part of the Tier 1 strategies, Creative Energy does not intend on proceeding with a subscription process prior to confirming the remaining Tier 2 strategies. While important, the voluntary subscription process will be costly and time consuming and on its own would be unlikely to address the residual financial gap for the project in the absence of Tier 2 strategies. Creative Energy also expects the City to confirm the terms of the land lease and other City enabling strategies, including likely future GHG policies for existing buildings, prior to the design and execution of the subscription process.

The package of Tier 1 strategies alone will not be sufficient to address the entire financial gap under base case assumptions in the feasibility study. But they can make a substantial dent – reducing the financial gap from about $156 million (after adjusting for a proposed federal floor on carbon prices by 2022) to $69 million or less. The sale of energy to the City's SEFC NEU would reduce the GHG emission reductions available for existing buildings by about 6,700 tonnes. However, GHG emissions from existing buildings could still be reduced by as much as 67% under the target size. Further, while the sale of energy to the SEFC NEU would help secure an investment in the Fuel Switch, this does not preclude advancing other low-carbon projects in the future to provide additional emission reductions –e.g., the second sewer heat pump at SEFC.

Tier 2 strategies will involve more effort and, in most cases, financial commitments from the City and/or other levels of government. Figure 45 shows three possible scenarios of Tier 2 strategies that could eliminate the residual financial gap and allow the project to proceed to the next stages of approvals, detailed design and construction.

Scenario 1 is entirely within the City's control. This scenario focusses on securing new development coupled with City financial enabling tools (as described in Table 53). The magnitude of the City's financial enabling tools would depend on how much new development can be secured for the project, which in turn depends on City policies. The study team has identified significant near-term development potential downtown and in South Cambie, which is one of the City's priority areas for district energy. No analysis has been conducted on North Cambie or the Broadway corridor, two other priority areas for district energy. A conservative estimate of new development over the next 10 years in downtown and South Cambie alone could reduce the residual financial gap by approximately $33 million. However, this will require the City to formalize carbon performance standards for new development and also design

98 The rationalization in property taxes is not a financial burden because the utility taxes on the interconnection and the site would not exist in the absence of this project. This strategy still includes property taxes on the target site at the Business and Other rate (Class 6), which is the most likely alternate use for the target site. There is a cost to purchasing low-carbon energy for City facilities relative to conventional energy. However, this is consistent with existing City policies and targets. And as demonstrated in this feasibility study the Fuel Switch would be the most cost-effective source of low-carbon energy for City facilities in most cases.

policies that allow the transfer of unallocated carbon credits created by the Fuel Switch to new developments not directly connected to the Fuel Switch as well as allow near-term developments to receive credit in advance of completion of the Fuel Switch project.[99] One of the advantages of this scenario is that it provides immediate and cost-effective GHG reductions for new development while also allowing additional time for completing larger interconnections, or for new thermal networks to reach a scale to support their own low-carbon supply projects.

Scenario 2 involves securing grants from senior levels of government to offset the high premium for GHG reductions in existing buildings under current market conditions and gaps in current carbon policy. The Province does not currently have any specific grant programs for large low-carbon heat projects such as the Fuel Switch.[100] However, the federal government has committed more than $180 billion for infrastructure to 2028, including $2 billion specifically for a proposed Low Carbon Economy Fund. The detailed structure and eligibility requirements for various federal funds have yet to be defined. But the Fuel Switch project aligns well with many of the stated policy objectives for these funds. Although the Fuel Switch project is a cost-effective source of GHG reductions, a grant will help secure this time-sensitive project in the face of a wide gulf between government climate targets and current climate policies. As a regulated public utility, any grant goes entirely to lowering project revenue requirement by reducing the capital costs that must be financed by Creative Energy. A grant could be made recoverable based on future changes in market conditions or carbon policies (e.g., increases in carbon prices or additional revenues). A $50 million federal grant would represent a substantial contribution to the project gap. This would be equivalent to about $40 / tonne of GHG reductions for existing buildings using the federal government's discount rate for project benefits. If necessary, the grant could also be tied to specific assets owned by the City (e.g., interconnection and/or building housing the Fuel Switch plant). The Province would likely need to

99 As discussed in Section 2 of this report, the City and Creative Energy had intended to use neighbourhood energy agreements to address the possible mismatch in timing between the larger Fuel Switch project and near-term development timelines. These agreements would also have secured future development to support near-term investments required in new networks as well as the larger Fuel Switch. The Commission has rejected the Neighbourhood Energy Agreement for NEFC. The City is now considering other approaches to achieving its policy objectives for deep, lasting and cost-effective carbon reductions.

100 For comparison, the Province has recently announced a $40 million Clean Energy Vehicle Program which will provide incentives of 5 to 6 thousand dollars for consumer purchases of between 5,000 and 6,500 electric vehicles. Phase 1 of the Fuel Switch project would reduce GHG emissions equivalent to about 16,500 cars.

support any application for federal infrastructure funds. In this scenario, there could still be some residual gap that could be filled through the sale of offsets to the Province. The sale of offsets to the Province would be another way for the Province to demonstrate support for federal funding.

Scenario 3 involves relying entirely on City financial enabling tools and the sale of offsets to the Province. This would retain the GHG reductions for existing buildings but would also entail greater financial commitments by the City. This would likely require the City to also own the building, which it could then finance with 100% debt and/or defer rent to reduce the financial gap.

These three scenarios are intended only to illustrate general themes, the different implications in terms of the City's financial commitments and near-term GHG reductions for existing buildings. There are many other possible levels and combinations of individual strategies. However, there are also possible interactions among individual strategies that would need to be considered in designing feasible packages. For example, increased sales to new development with formal carbon performance standards (whether via direct connections or the transfer of carbon credits) could substantially reduce the financial gap, but would also lower the magnitude of GHG emission reductions that could be sold as offsets to the Province.

Tier 3 represents strategies that could reduce the initial financial gap or reliance on other financial enabling tools, but would also add to project complexity (e.g., CHP) or lower initial project benefits and increase carbon abatement costs (e.g., reducing the size). Some strategies could not be confirmed until the detailed design, construction and/or operating phases (i.e., additional design optimizations, capital cost savings, or operating synergies). Given the uncertain lead time for the Fuel Switch project at this time, it is not possible to predict yet whether the BC Hydro SOP will be available for this project. Both phasing and CHP could be considered as fall backs in the event other enabling strategies fall through. Further project optimizations and cost savings in the design, construction and operating phases should be pursued to enhance project benefits, reduce rates, and/or accelerate the recovery of financial commitments from the City or other levels of government.

Figure 45: *Alternate Packages of Policies and Strategies to Enable the Creative Energy Fuel Switch*

BASE CASE	
Financial Gap	$156 million [1]
GHG Emission Reductions Allocated to Existing Buildings	67,500 tonnes / year [2]

TIER 1 ENABLING STRATEGIES	
Design optimizations for interconnection	
Rationalize property taxes	
Contract with SEFC NEU	
Government leadership in purchasing low-carbon energy	
Voluntary subscription process for non-governmental buildings	
Residual Financial Gap	$69 million
GHG Emission Reductions Allocated to Existing Buildings	60,000 tonnes / year

TIER 2 ENABLING STRATEGIES			
	Scenario 1	**Scenario 2**	**Scenario 3**
	Maximum Sales to New Development	Federal Grants ($50 million)	Maximum City Financial Enabling Tools ($50+ million)
	Moderate City Financial Enabling Tools ($0-30 million)	Provincial Offsets	Provincial Offsets
Residual Financial Gap	0	0	0
GHG Emission Reductions Allocated to Existing Buildings	26,000 tonnes / year	60,000 tonnes / year [3]	60,000 tonnes / year [3]

TIER 3 ENABLING STRATEGIES (RESERVE STRATEGIES)			
	Reduce Size	**Incorporate CHP**	**Additional Capital and Operating Cost Savings**
Additional Reduction in Financial Gap	$20 million	$5 – 7 million	TBD [4]
Reduction in GHG Emissions Available for Existing Buildings	19,000 tonnes / year	None [5]	None

(1) Reflects base case assumptions in the feasibility study for project costs, future gas prices, and future carbon prices. Carbon price forecasts include the effect a proposed federal floor that would increase carbon taxes in B.C. from $30 / tonne to $50 / tonne by 2022.

(2) This is equivalent to a 75% reduction for all existing Creative Energy customers. The target size for Phase 1 of the Fuel Switch would eliminate 81,500 tonnes of GHG emissions, but 14,000 tonnes are already allocated to new development in the base case analysis.

(3) Sale of offsets to the Province would be limited to reductions for existing non-governmental buildings. Sale of offsets would not affect community emission inventories. Sale would be limited to 10 years and would reduce the near-term reductions that voluntary customers would legally own. But this can be used to phase in the long-term reductions for existing buildings.

(4) Additional capital and operating cost savings will require further due diligence and may not be confirmed prior to detailed design, construction and/or actual operating phases. If available, these savings could be used to increase project benefits, reduce rates, and/or accelerate repayment of grants or City financial enabling tools.

(5) This assumes the plant is upsized and pressure is uprated so as to make available the same 65MW of steam downstream of CHP. Other configurations of CHP may reduce GHG reductions available from heat production.

Table 53: Detailed Description of Tier 1 Fuel Switch Enabling Strategies

STRATEGY	INCREMENTAL REDUCTION IN FINANCIAL GAP (MILLIONS)
Optimize Design of New Interconnection: This could include tunneling under the railyards, utilizing the SkyTrain alignment, and/or coordinating the interconnection project with the removal of the viaducts in NEFC. These strategies could reduce the cost of the interconnection by half, but they will require support from the City and negotiations with other agencies.	$11.6
Rationalize Property Taxes: As noted in the report, B.C. is unique in Canada in having a utility classification for property tax assessment. The current utility mill rate in Vancouver is more than three times the rate for light industry or business, and even higher than the rate for major industry.* Even in the absence of provincial policy changes, the City could eliminate property taxes on the interconnection through ownership of the line and could reduce property taxes on the City-owned site for the Fuel Switch plant to the Business and Other rate through a gross lease for the site.	$27.5
Contract with SEFC NEU: The City will require new low-carbon supply to meet planned growth in SEFC. The Fuel Switch project is expected to be less costly than an additional heat pump in the City's existing sewer heat recovery plant. The sale of energy to SEFC, which serves new development, would reduce the GHG reductions available for existing buildings downtown. However, if or when the Fuel Switch capacity is required downtown, the City could still proceed with the installation of an additional sewer heat pump.	$13.5
Government Leadership in Purchasing Low-Carbon Energy: About 17% of existing customers are buildings controlled by the City, the Province and the federal government. There are also some large existing government buildings that are currently heated with on-site gas boilers that could also be connected to the Fuel Switch. This strategy assumes government buildings purchase 75% of their annual energy at the full cost of the Fuel Switch. This is the maximum reductions available from a baseload energy plant assuming equal allocations to all customers. However, it would also be possible to allocate more of the annual output from the Fuel Switch to government buildings if less energy is allocated to other existing customers or buildings. The incremental cost of energy from the Fuel Switch exceeds the current cost of offsets for Public Service Organizations (PSOs) in B.C., but the cost would be fixed, reducing exposure to volatile natural gas prices and uncertain future offset costs. As demonstrated in the feasibility study, the Fuel Switch currently represents the lowest cost alternative for achieving deep reductions in GHG emissions from government buildings.	$27+
Voluntary Subscription Process for Non-Governmental Buildings: Preliminary research and anecdotal evidence suggests some market demand for low-carbon energy among large commercial customers. This would be confirmed through a voluntary subscription process. The range of impact assumes about 100,000 MWh of energy is sold at a premium of 15% relative to current gas and carbon price forecasts. This represents less than 30% of current steam sales. For a customer purchasing 75% of their annual energy from the Fuel Switch, this would translate into a total bill premium of roughly 11%. The final subscription offer would be designed in consultation with customers and the City. The price would likely be allowed to escalate with underlying changes in gas and carbon prices, but could also be capped given the fixed costs of the Fuel Switch. The success of the subscription offer could be enhanced through greater clarity from the City and other levels of government on future carbon policies that may affect existing buildings.	$5 – $10

* The analysis in this feasibility study highlights a possible barrier for other utility-scale low-carbon projects in B.C.

Table 54: Detailed Description of Tier 2 Fuel Switch Enabling Strategies

STRATEGY	INCREMENTAL REDUCTION IN FINANCIAL GAP (MILLIONS)
Sales to New Development: The Fuel Switch represents a cost-effective source of low-carbon energy or carbon credits for new development that has formal carbon performance requirements. The base case analysis for the feasibility study assumes only 17% of the Fuel Switch capacity would be allocated to new development in NEFC and South Downtown, which would both lower rates in these neighbourhoods and provide additional economies of scale for the project. The study team has identified considerable additional development potential in other parts of downtown and South Cambie. The team did not have the scope or data to assess development potential in North Cambie or the Broadway corridors, which are also priority zones for district energy in Vancouver. Securing all identified development over the next 10 years in downtown and South Cambie alone would reduce the gap between $15 and 35 million. In light of recent Commission decisions regarding a proposed neighbourhood energy agreement in NEFC, the City will need to develop alternate policies to formalize carbon performance standards for individual developments, together with mechanisms to permit the transfer of unallocated carbon credits from the Fuel Switch (to developments not connected to the existing network) and mechanisms to allow early adopters to take credit for the Fuel Switch if development approvals are required before completion of the Fuel Switch.	$15 – $35+
Federal Grants: The federal government has committed more than $180 billion for infrastructure to 2028, including $2 billion specifically for a proposed Low Carbon Economy Fund. The structure and eligibility requirements for new federal funds have yet to be defined. But the Fuel Switch project aligns with many of the stated policy objectives for these federal funds. Given the purpose of the grant is to bridge gaps between government targets and current market conditions and carbon policies, a recoverable grant tied to future increases in gas and carbon prices would be enough to advance the Fuel Switch project. A recoverable grant would allow the government to support a cost-effective but time-sensitive project to reduce carbon emissions but also ensure recovery of funds if and when carbon policies catch up with government targets.	$50+
City Financial Enabling Tools: The City could defer land rent and residual property taxes for the plant site, and tie recovery of those to future increases in natural gas and carbon prices. The City could also own portions of the infrastructure (e.g., the interconnection and/or the building that will house the plant). The City could in turn finance those pieces of infrastructure with 100% debt and/or also tie recovery of those costs to future gas and carbon prices. In the absence of substantial changes in gas and carbon prices, the present value of the City financial commitments could be $30 – 50 million. The lower boundary assumes the City only owns the interconnection and land, and defers land rent, property taxes (for the plant site), and fees for use of the interconnection. The upper boundary assumes the City would also own the building and defer payments for the use of the building. Except for debt financing costs on new infrastructure, the bulk of the City's financial enabling tools would be in the form of deferred revenues.	$0 – $50

STRATEGY	INCREMENTAL REDUCTION IN FINANCIAL GAP (MILLIONS)
Provincial Offsets: In the absence of grants, one tangible way for the Province to support the project is through the purchase of offsets for its carbon neutral government commitments. The GHG reductions from the Fuel Switch are equivalent to about 13% of the GHG offsets purchased by the Province in 2015. The Province will require new sources of offsets as its current portfolio begins to expire in the coming years. The Province has historically paid very low prices for offsets, but most of its existing portfolio is from low-cost forest sequestration projects. The Province has indicated a desire to diversify its portfolio, including purchasing offsets from projects in the building sector. The Fuel Switch represents a potentially large source of high quality offsets. The regulated open books of this type of project offers considerable transparency of costs. Only voluntary reductions would be eligible for offsets and under provincial accounting rules the City can still take credit within community emission inventories for any local reductions sold as offsets. The Province would typically purchase offsets for a maximum term of 10 years (with renewal options). However, the sale of offsets could reduce the near-term gap and help to phase in reductions for existing buildings. Current prices for offsets are too low to have a meaningful effect on the financial gap. However, the study team has proposed an innovative dynamic pricing approach to secure a higher base price for offsets but also allow the price to decline with increases in gas and/or carbon prices over time. Similar to a recoverable grant this would reduce the immediate financial gap while ensuring the federal and provincial governments receive the benefit of future changes in their carbon prices and policies. The purchase of offsets by the Province could also be one means to secure federal grants. The City has a role to play in establishing the policy framework that will determine what portion of GHG reductions from the project are voluntary and whether those reductions should be eligible for sale as offsets. The sale of offsets could also crystalize losses associated with near-term GHG reductions (versus banking those reductions for other community uses) and this could affect the level of other enabling strategies ultimately required from the City.	$10 – $15

Table 55: *Detailed Description of Tier 3 Fuel Switch Enabling Strategies*

STRATEGY	INCREMENTAL REDUCTION IN FINANCIAL GAP (MILLIONS)
Decrease Size: There are considerable economies of scale for the Fuel Switch project. These reflect economies of scale in plant equipment and operations (staffing), but also fixed upfront costs for a new interconnection, site and building. However, it may still be possible to phase equipment within the plant to reduce initial investment risks in the absence of sufficient contracts or other enabling strategies. Decreasing the initial size of the plant from 65 MW to 45 MW would reduce the financial gap by $20 million. However, this would also increase the unit cost of remaining energy from the Fuel Switch about 11%. There would also be a reduction in available GHG savings (62,000 tonnes vs. the base case of 81,000 tonnes per year). And the implicit cost of carbon abatement for a smaller plant would increase about 17.5% relative to the base case.	$20

STRATEGY	INCREMENTAL REDUCTION IN FINANCIAL GAP (MILLIONS)
Combined Heat and Power (CHP): It would be technically possible to add about 7 MW of electricity production to the Fuel Switch plant (assuming the base project size of 65 MW of steam output). Under current standing offer prices from BC Hydro this would reduce the financial gap about $5 – 7 million. However, it would increase the annual fuel requirements and overall project complexity. This option may also be off the table soon as BC Hydro is reviewing the Standing Offer. With the completion of Site C, BC Hydro may be long on power could discontinue the SOP until excess generation from Site C is fully absorbed.	$5 – $7
Additional Capital and Operating Cost Savings: The feasibility study identified a number of possible project optimizations including using dual fuel boilers, increasing summer demand, and additional staffing synergies with the existing steam plant. There are likely others. These will require more due diligence and would likely not be confirmed until the design, construction and/or operating stages. The savings could be used to increase project benefits, reduce rates, and/or accelerate the recovery of grants and other financial enabling tools.	TBD

Given the size, complexity, and lead-time for the Fuel Switch, it may be necessary to pursue various strategies in parallel in order to secure this time-sensitive legacy. Commitments of new development or City financial enabling tools can be used to support further project development in advance of confirming grants or the results of a voluntary subscription process. In the event that grants or voluntary subscriptions exceed targets, then more of the project could be allocated to existing buildings and/or reliance on City financial enabling tools could be reduced.

The City has established aggressive targets for renewable energy and GHG reductions by 2020 and beyond. Given the current stage of discussions with the City and other levels of government it is unlikely the project could be complete by 2020. The final project schedule is uncertain because it will depend on the timing of near-term decisions required from the City and other levels of government with respect to the various strategies discussed above, and also timelines for regulatory approvals. Figure 46 depicts the key implementation tasks and specific time requirements for later project stages. These include the following:

- ***Construction and Commissioning:*** Construction of the project will require at least 18 months following tendering and detailed design to functional certification. Once constriction and functional certification are complete, an additional year is typically required to fully commission and optimize the project. Any performance guarantees would normally apply only after full commissioning. However, during the extended commissioning period the plant would be operational and can still make a substantial contribution to GHG reductions.

- ***Tendering and Design:*** Tendering and detailed design will require at least 6 months. This assumes the development of tender documents can be completed in advance of final regulatory approvals. Creative Energy has not established a final approach to the tendering and design phases. Aspects of the project may be tendered as design-build.

- ***BCUC Approvals:*** Creative Energy cannot commence construction prior to receipt of a CPCN from the Commission. A utility would normally also not begin detailed design and/or tendering until receipt of a CPCN. Based on recent experience, the CPCN process for a project of this complexity and size could take 8 – 12 months from filing to receipt of a Commission decision. Creative Energy would likely also require approval of subscription contracts and possibly specific rates or rate

setting parameters in advance of construction. The BCUC process could be written or oral and would likely involve several rounds of information requests, plus final submissions.

- ***Preparation of CPCN Application:*** The application will require at least 3 months to prepare. Depending on the timing of a project enabling agreement with the City and other pre-CPCN development tasks, there may be significant updates required to the preliminary project design and costing information to meet the Commission requirements for a CPCN application. There are a number of development tasks that should start prior to submission of the CPCN but may not be completed until after. Examples include the application for an air quality permit, the fuel procurement process, and community consultation. A significant portion of community consultation will need to be complete prior to the CPCN submission under the Commission's CPCN guidelines. Creative Energy also expects that it will confirm at least 50% of the fuel supply prior to the CPCN submission, with the remainder confirmed prior to commencing construction.

- ***Project Enabling Agreement:*** A key step to advance the Fuel Switch to the CPCN stage will be a Project Enabling Agreement with the City of Vancouver. At a minimum, this agreement should include:

  - mutual understanding of project goals, scope and structure, including any City ownership of project components and the eligibility of various enabling strategies such as offset sales to the Province,
  - land lease (including option on neighbouring site),
  - commitments to purchase Fuel Switch energy or carbon credits for City buildings,
  - commitments of City-controlled urban wood waste,
  - a purchase agreement with the City's SEFC NEU,
  - any policy commitments and financial enabling tools to be provided by the City to advance the project, including cost recovery mechanisms,
  - respective roles and responsibilities of the City and Creative Energy in project development and operation, including securing project optimizations (e.g., interconnection optimizations), securing grants, project approvals, performance requirements, and long-term governance, and
  - termination, default and security provisions in relation to each party's commitments.

  The Project Enabling Agreement is the most critical next step in the project development. This agreement will be necessary to secure grants, commence the voluntary subscription process for existing customers, commence formal discussions on offset sales with the Province (if applicable), commence community consultations, and prepare a full CPCN application.

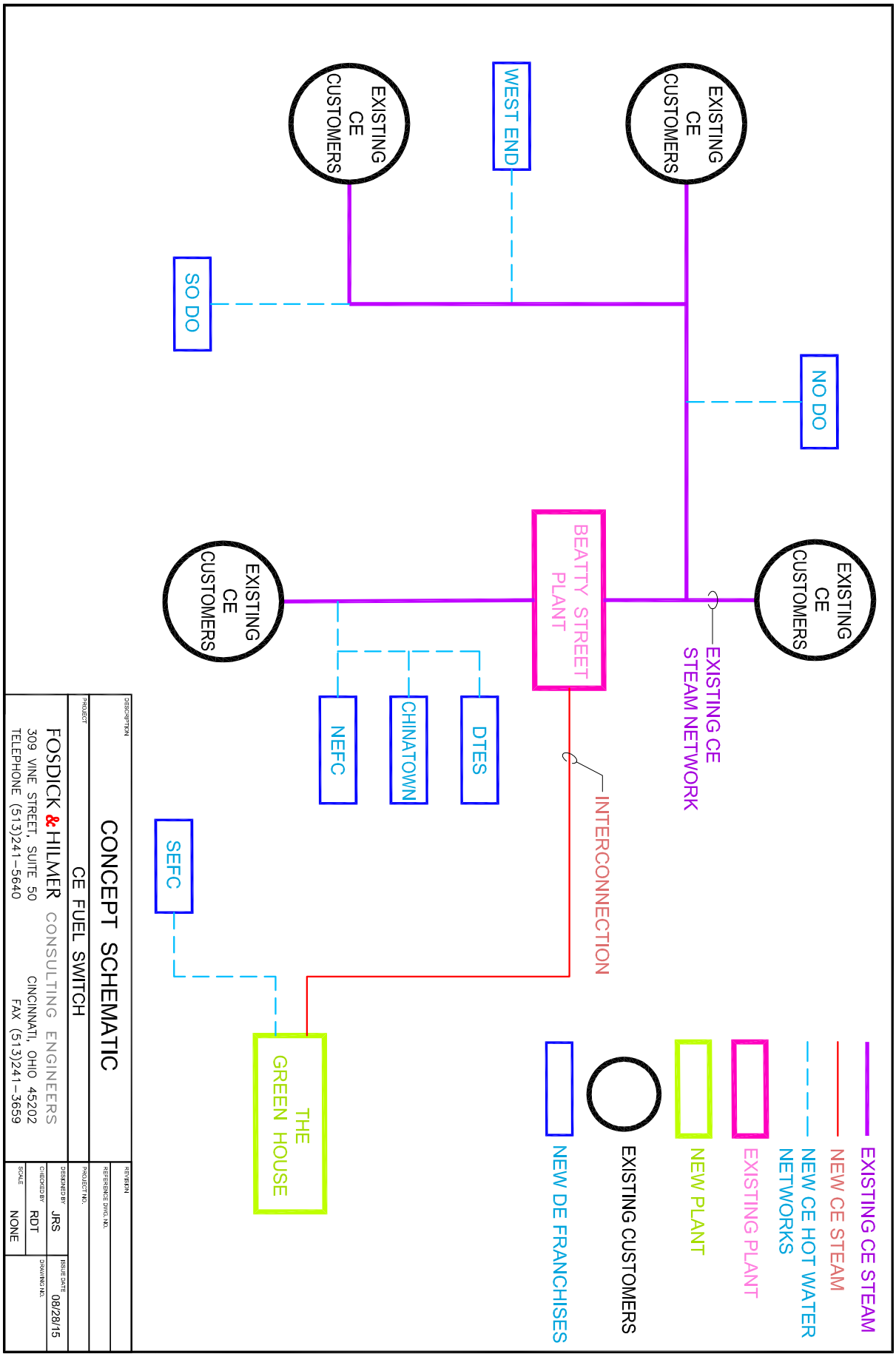
- ***Voluntary Subscription Process:*** The design of the subscription offer and process will depend on the Project Enabling Agreement with the City. This process could take 6 months and will need to be largely complete prior to filing a CPCN application.

- ***Fuel Procurement Strategy:*** Creative Energy has conducted considerable research on fuel supply. A final procurement strategy will be developed following completion of the Project Enabling Agreement. Creative Energy expects to secure 50% of the fuel supply prior to filing the CPCN, with the remainder secured by commencement of construction. Fuel procurement may include a mix of contract and business arrangements.

Figure 46: Preliminary Project Schedule

APPENDIX A

F&H ENGINEERING DRAWINGS AND SCHEMATICS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CONCEPT SCHEMATIC
PROJECT
CE FUEL SWITCH
FOSDICK & HILMER CONSULTING ENGINEERS
309 VINE STREET, SUITE 50
CINCINNATI, OHIO 45202
TELEPHONE (513)241-5640
FAX (513)241-3659
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CHECKED BY RDT
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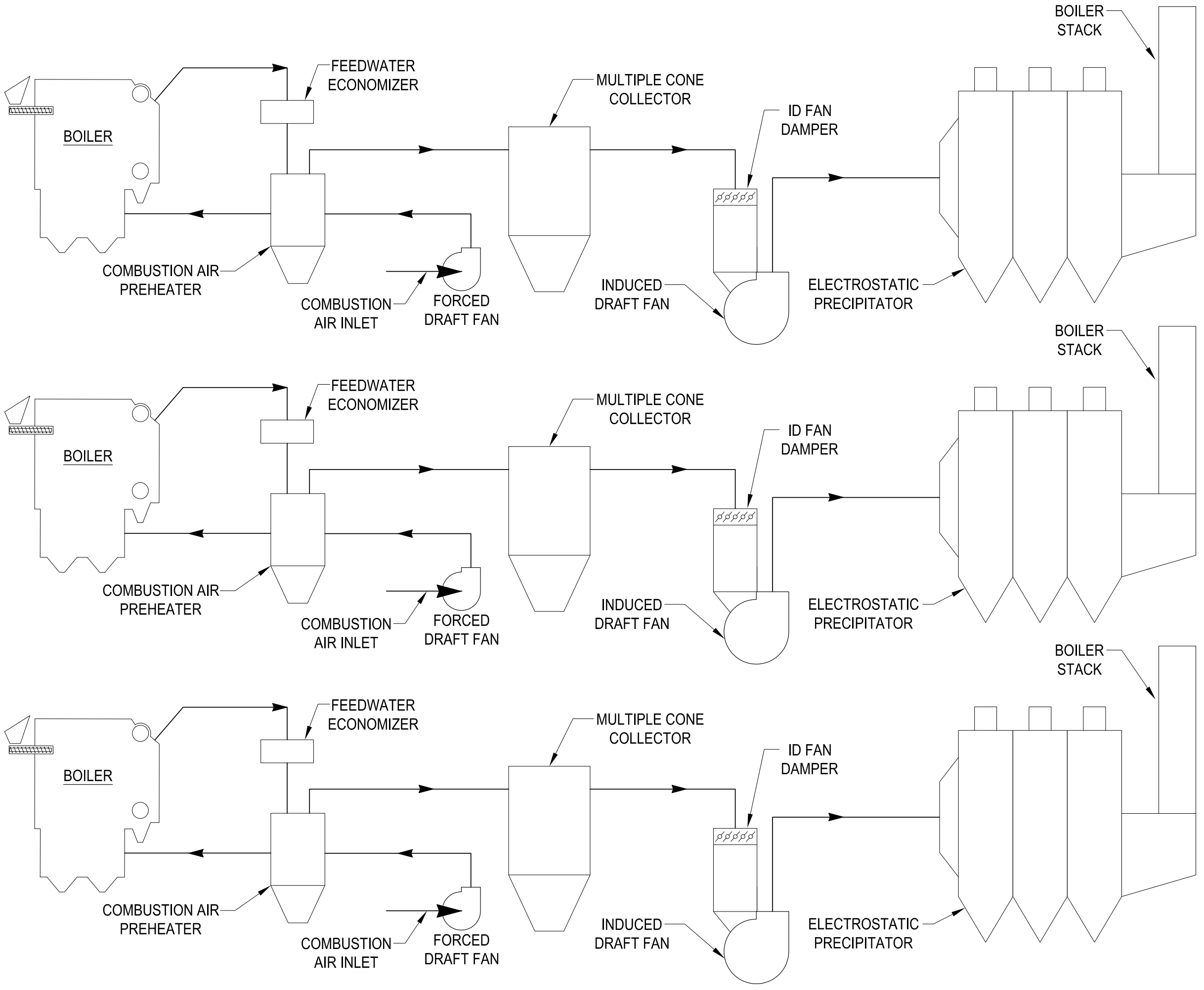

DESCRIPTION COMBUSTION AIR & FLUE GAS FLOW SCHEMATIC	REVISION		
	REFERENCE DWG. NO.		
PROJECT THE GREEN HOUSE - BASE 1	PROJECT NO.		
FOSDICK & HILMER CONSULTING ENGINEERS 309 VINE STREET, SUITE 50 CINCINNATI, OHIO 45202 TELEPHONE (513)241-5640 FAX (513)241-3659	DESIGNED BY	SPT	ISSUE DATE 10/30/2015
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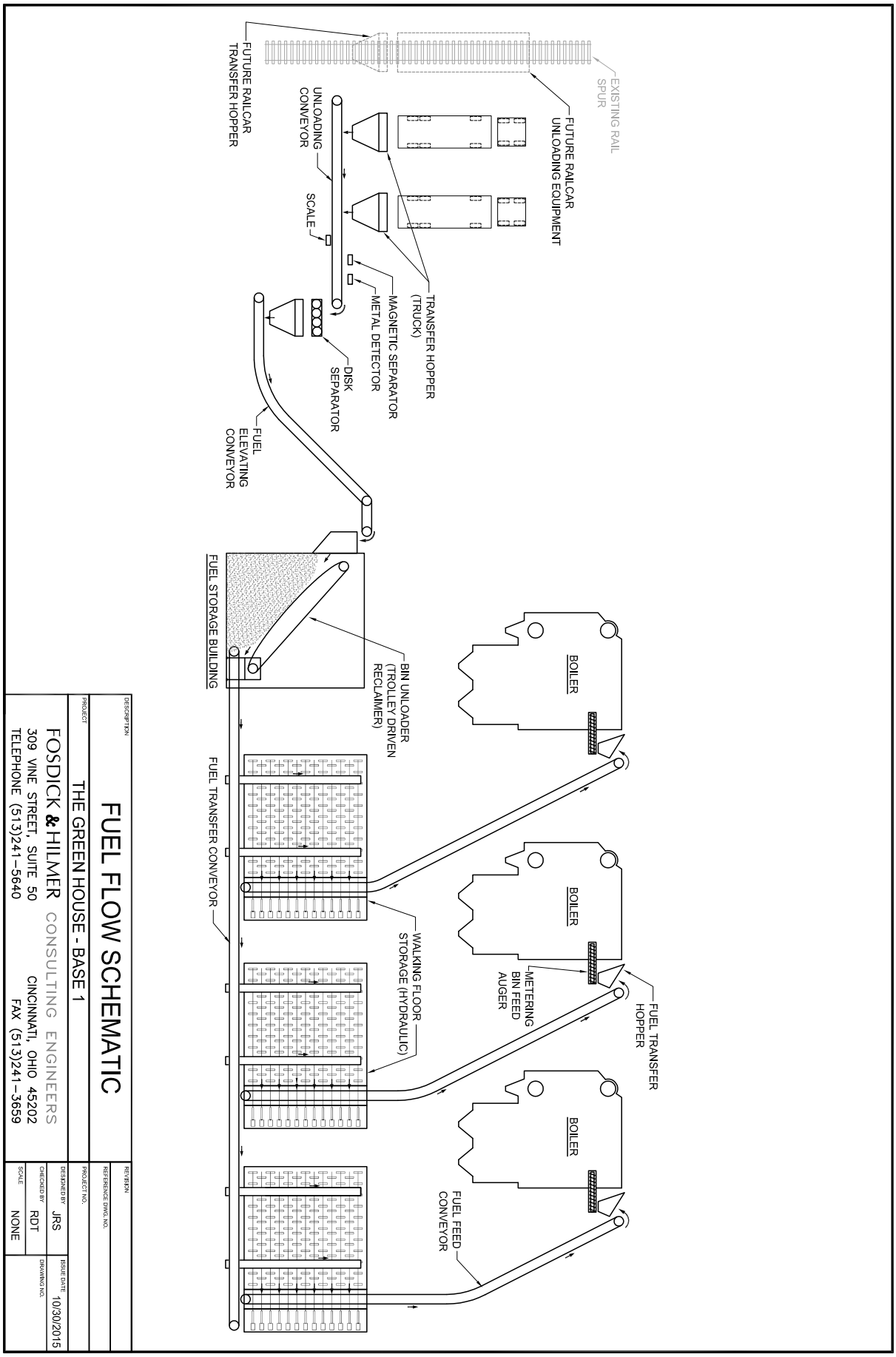
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FUTURE RAILCAR TRANSFER HOPPER
UNLOADING CONVEYOR
SCALE
TRANSFER HOPPER (TRUCK)
MAGNETIC SEPARATOR
METAL DETECTOR
DISK SEPARATOR
FUEL ELEVATING CONVEYOR
FUEL STORAGE BUILDING
BIN UNLOADER (TROLLEY DRIVEN RECLAIMER)
FUEL TRANSFER CONVEYOR
BOILER
BOILER
BOILER
WALKING FLOOR STORAGE (HYDRAULIC)
METERING BIN FEED AUGER
FUEL TRANSFER HOPPER
FUEL FEED CONVEYOR
DESCRIPTION
FUEL FLOW SCHEMATIC
PROJECT
THE GREEN HOUSE - BASE 1
FOSDICK & HILMER CONSULTING ENGINEERS
309 VINE STREET, SUITE 50 CINCINNATI, OHIO 45202
TELEPHONE (513)241-5640 FAX (513)241-3659
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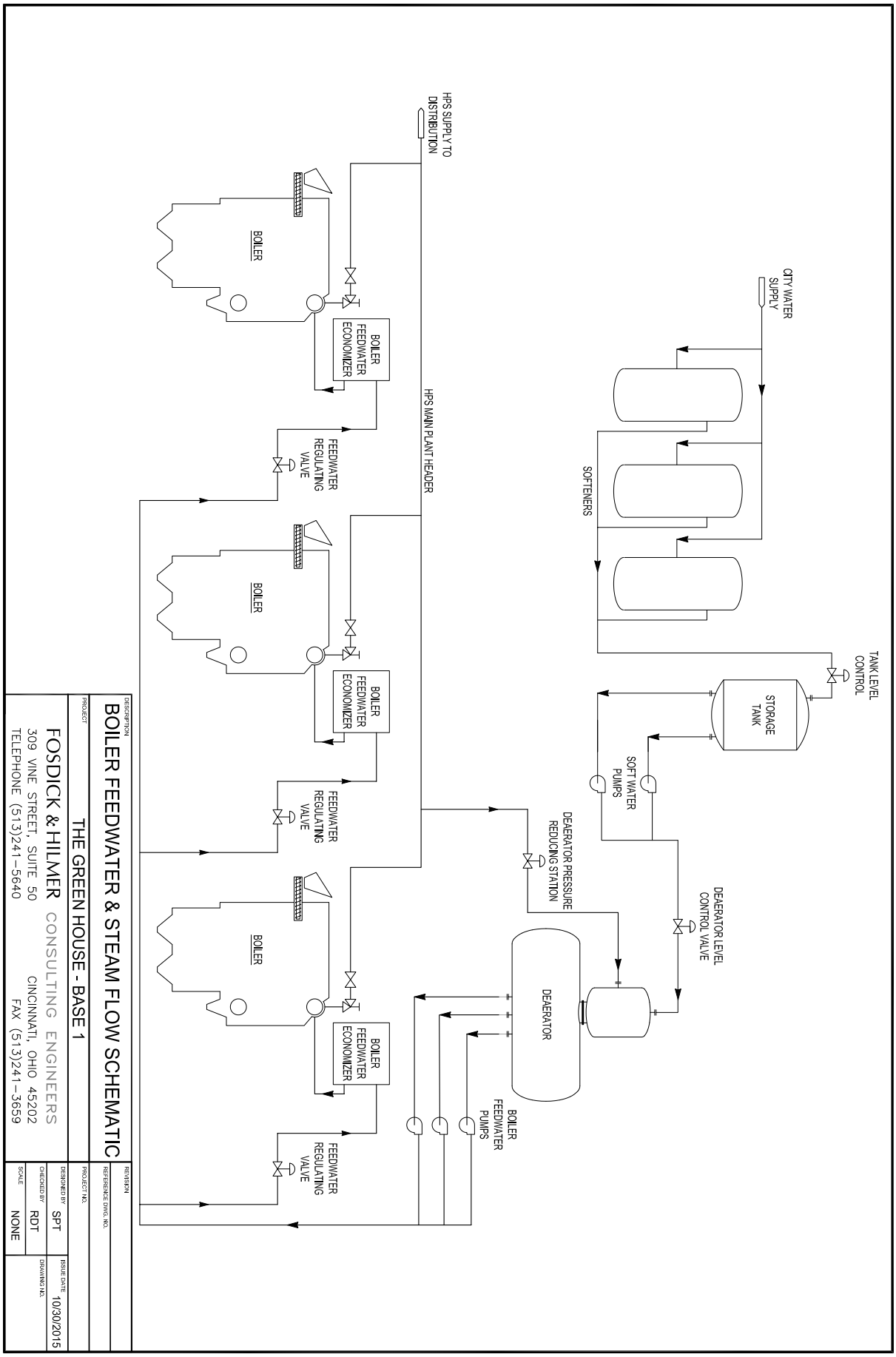
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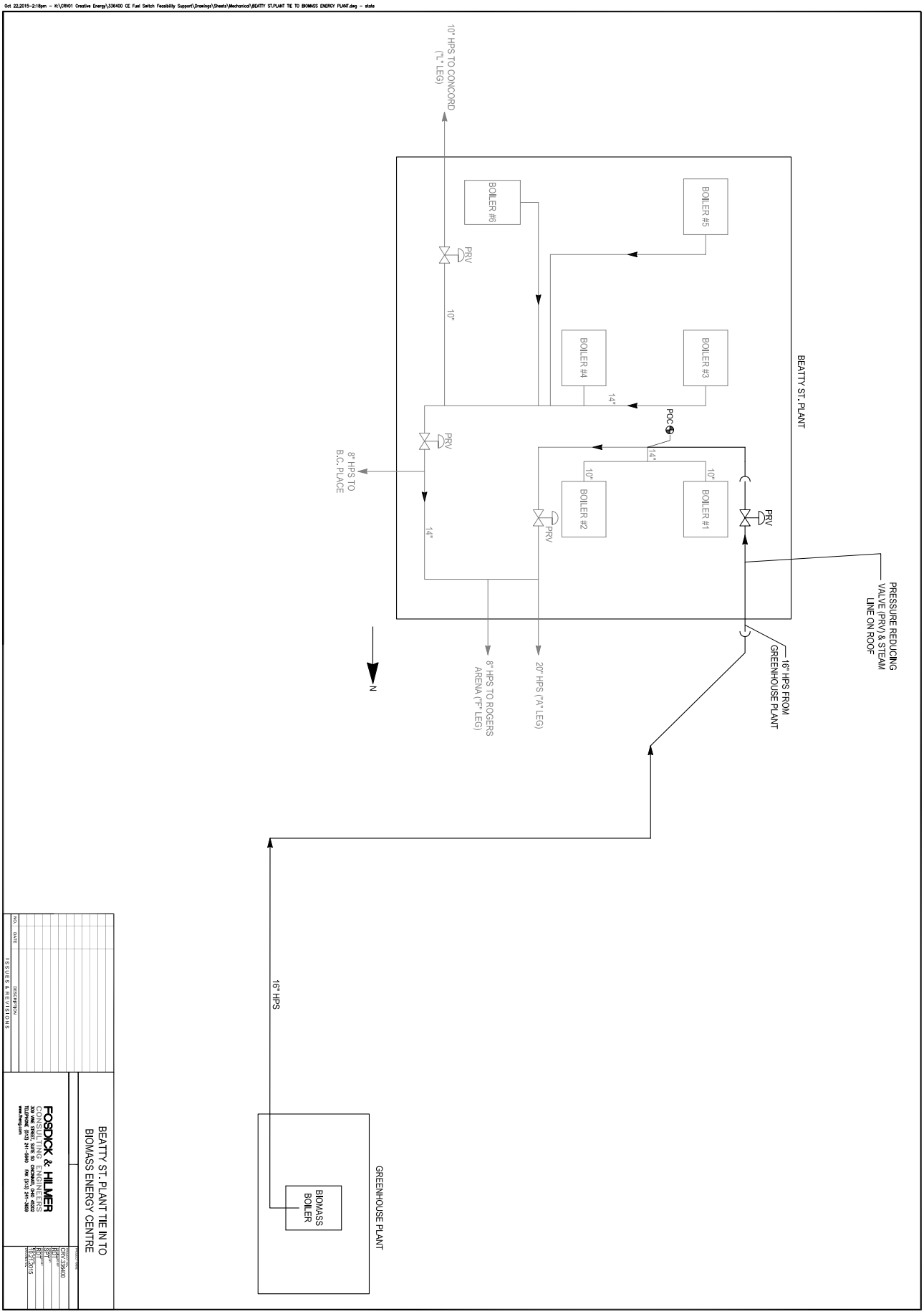
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BOILER #1
BOILER #2
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PRV
PRV
PRV
POC
14"
14"
14"
10"
10"
10"
10" HPS TO CONCORD ("L" LEG)
8" HPS TO B.C. PLACE
8" HPS TO ROGERS ARENA ("F" LEG)
20" HPS ("A" LEG)
16" HPS FROM GREENHOUSE PLANT
PRESSURE REDUCING VALVE (PRV) & STEAM LINE ON ROOF
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16" HPS
GREENHOUSE PLANT
BIOMASS BOILER
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PROJECT NUMBER
CRV-336400
DRAWN BY
RDW
CHECKED BY
RDW
DATE
OCT 22,2015
SCALE
NTS
FOSDICK & HILLMER
CONSULTING ENGINEERS
320 VINE STREET, SUITE 50, CINCINNATI, OHIO 45202
TELEPHONE (513) 241-5490 FAX (513) 241-5809
www.fhengr.com
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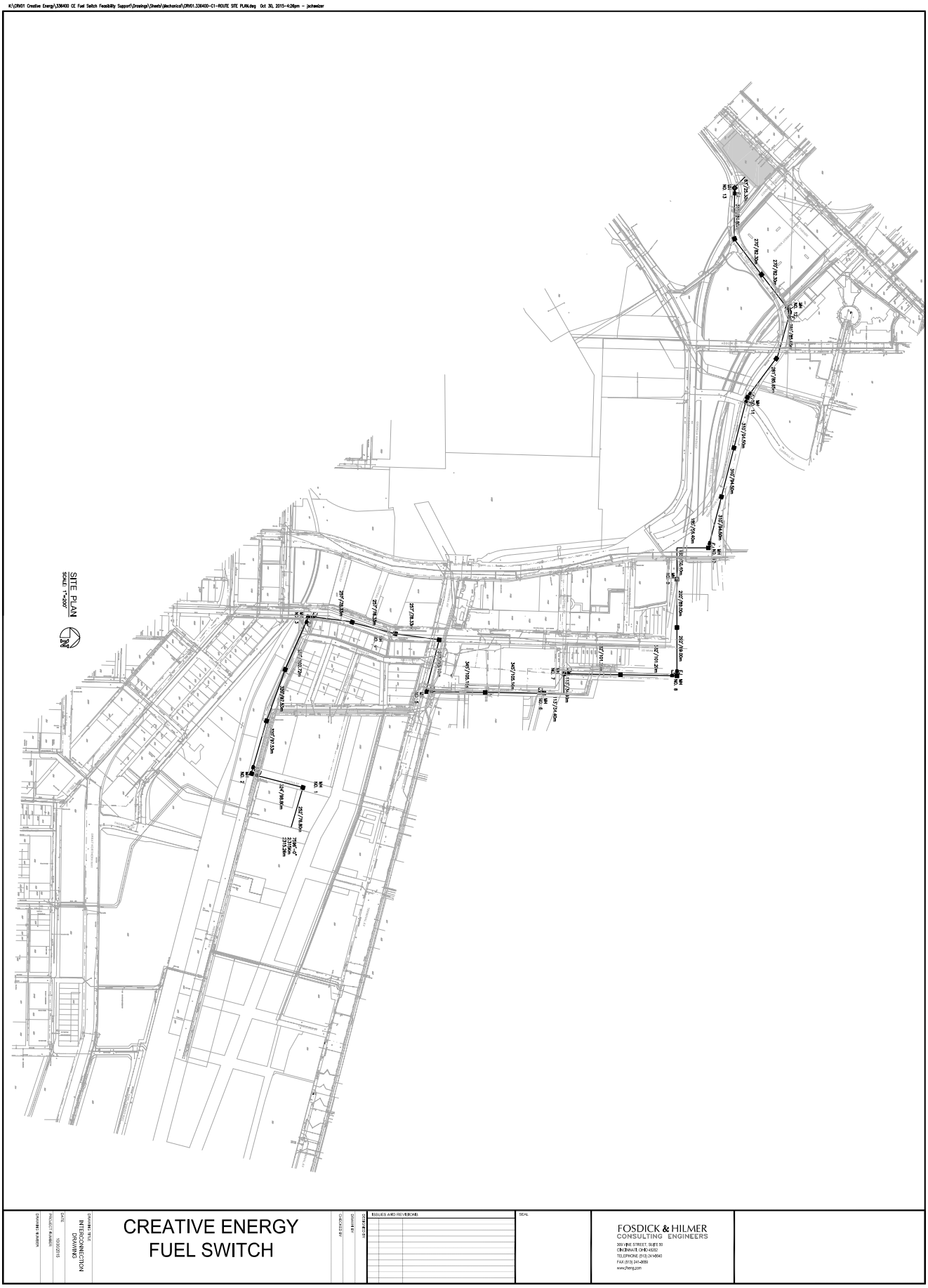
ISSUES & REVISIONS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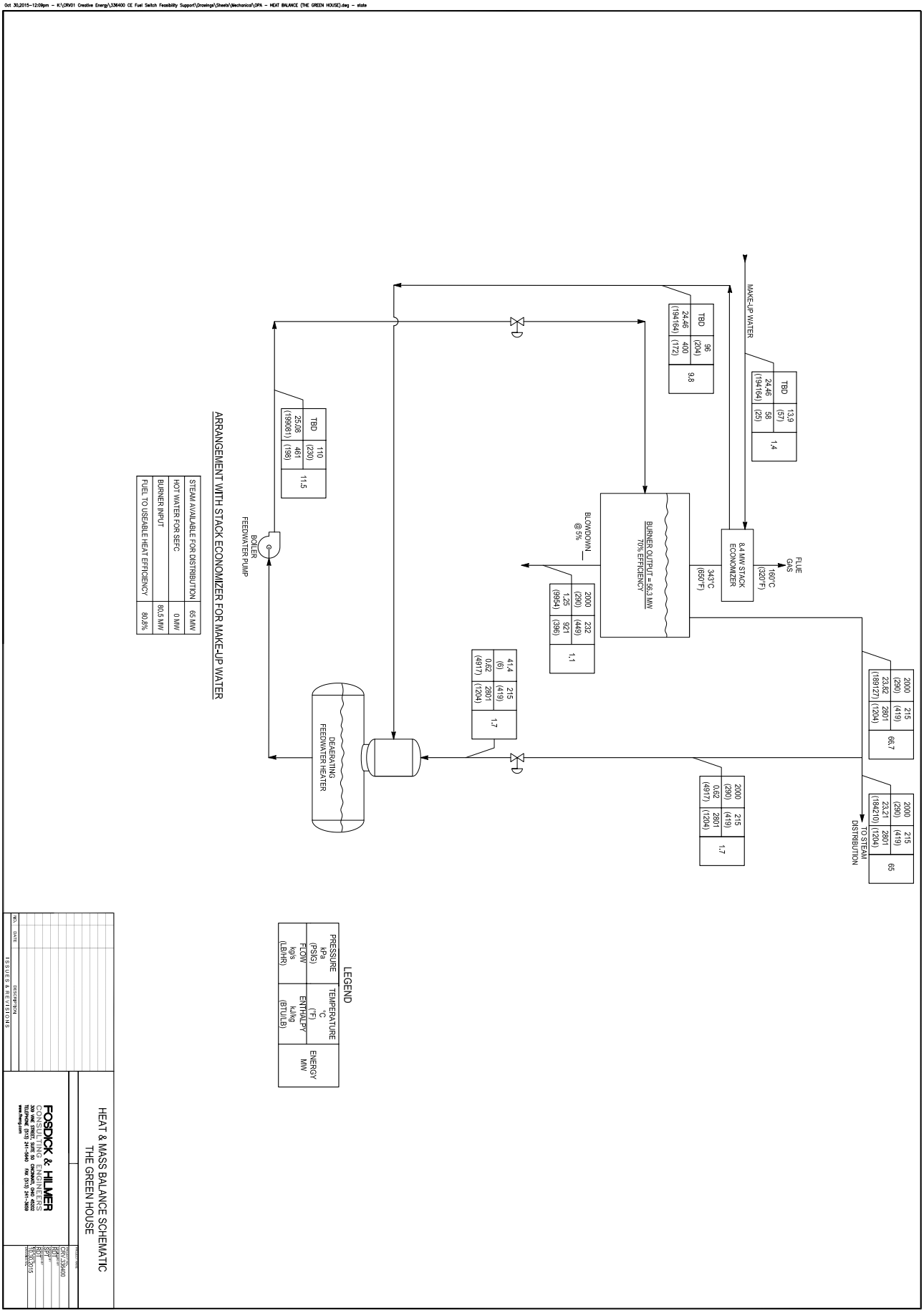
CONSULTING ENGINEERS
ISSUES AND REVISIONS
SEAL

Oct 30,2015-12:09pm - K:\CRVO1 Creative Energy\336400 CE Fuel Switch Feasibility Support\Drawings\Sheets\Mechanical\DPA - HEAT BALANCE (THE GREEN HOUSE).dwg - state



SITE SERVICES - PRELIMINARY LINE SIZING

Service	Line size	Assumptions
Water	8"	100% make-up water; 4% boiler blowdown rate
Sanitary sewer	12"	Sanitary includes plant process waste water
Storm sewer	15"	Roof area 70,000 sf ; max rainfall 4 inches/hr. Site runoff not included
Natural gas	6"	Gas can be fired as a full sized back-up in the biomass boiler. Service is available from the local utility at 100 psig with a 600 ft run to the plant's pressure regulating station
Power	(4) 4" conduits w/contents of ea. conduit@ (4) 500 kcmil cables & (1) #3/0 GND	1000 kw transformer rated at 1250 kVA @.8 power factor; secondary FLA @ 1200 amps & 600 V. Power to primary side of transformer by others.

LIST OF ACCOMPANYING REPORTS

Levelton Air Quality Assessment

Ipsos Stakeholder Consultation Report

KWL Hot Water Conversion Memo

ICON Building Cost Estimate

RESHAPE
STRATEGIES

Appendix B

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

An Application by Creative Energy Vancouver Platforms Inc. (Creative Energy) for acceptance of a Long-Term Resource Plan

BEFORE:

O R D E R

WHEREAS:

A. On June 9, 2017, Creative Energy applied (Application) to the Commission for an Order, pursuant to section 44.1(6) of the *Utilities Commission Act*, to accept its Long-Term Resource Plan (Creative Energy LTRP).

B. Creative Energy's filing responds to a Directive in the Commission's Decision dated June 9, 2015 regarding the Creative Energy 2015-17 Revenue Requirement Application: "…Creative Energy must file a long-term resource plan pertaining to the existing steam utility no later than two years from the date of this Decision and prior to making an investment decision regarding any low carbon fuel switch that may impact the existing steam customers. The LTRP shall include information available from the fuel switch feasibility study." (p. 15).

C. In its Decision granting a Certificate of Public Convenience and Necessity for Northeast False Creek (NEFC) dated December 8, 2015 the Commission also concluded: "…NEFC is not a separate utility from the existing utility. In this circumstance, the Panel is [sic] also finds that the LTRP filing previously directed for the utility includes NEFC." (p. 71).

D. The LTRP presents a long-term plan to reduce greenhouse gas (GHG) emissions within Creative Energy's existing steam network through the use of clean urban wood waste (the "Fuel Switch Project").

The Creative Energy LTRP analyzes the external regulatory, policy and planning environment

within which Creative Energy is required to develop the Fuel Switch Project. The Creative Energy LTRP also compares the cost-effectiveness of the Fuel Switch Project with the status quo, other project alternatives, and other low-carbon energy benchmarks.

E. Section 44.1(5) of the UCA provides that the Commission may establish a process to review a long-term resource plan.

F. The Commission has determined that a **[NTD: to be completed by Commission following decision on need for and form of a proceeding]**

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. The Regulatory Timetable for review of the Creative Energy Long-Term Resource Plan Long Term Electric Resource Plan (Creative Energy LTRP) is set out in Appendix A to this order.

2. Creative Energy is to publish, as soon as possible, the Public Notice, attached as Appendix B to this Order, in such local and community newspapers as to provide adequate notice to those parties who may be affected by the plans outlined in the Creative Energy LTRP.

3. Creative Energy must provide a copy of this Order to the key parties consulted in Creative Energy's Stakeholder engagement outlined in Section 13 of Appendix A, Creative Energy LTRP.

4. The Creative Energy LTRP, together with any supporting materials, will be available for inspection at Creative Energy Office, 920 Beatty Street, Vancouver, BC V6B 2M1. . The Creative Energy LTRP and supporting materials will also be available on the Creative Energy website at www.creativeenergycanada.com.

5. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/Registration-Intervener-1.aspx, by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the Commission's Rules of Practice and Procedure.

DATED at the City of Vancouver, in the Province of British Columbia, this XX day of XXXX, 2016.

BY ORDER

Original Signed By:

Panel Chair/Commissioner

Attachment

Appendix C

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

and

An Application by Creative Energy Vancouver Platforms Inc. (Creative Energy) for acceptance of a Long-Term Resource Plan

BEFORE:

O R D E R

WHEREAS:

A. On June 9, 2017, Creative Energy applied (Application) to the Commission for an Order, pursuant to section 44.1(6) of the *Utilities Commission Act*, to accept its Long-Term Resource Plan (Creative Energy LTRP). This is Creative Energy's first LTRP for the existing steam utility.

B. Creative Energy's filing responds to a Directive in the Commission's Decision dated June 9, 2015 regarding the Creative Energy 2015-17 Revenue Requirement Application: "…Creative Energy must file a long-term resource plan pertaining to the existing steam utility no later than two years from the date of this Decision and prior to making an investment decision regarding any low carbon fuel switch that may impact the existing steam customers. The LTRP shall include information available from the fuel switch feasibility study." (p. 15).

C. In its Decision granting a Certificate of Public Convenience and Necessity for Northeast False Creek (NEFC) dated December 8, 2015 the Commission also concluded: "…NEFC is not a separate utility from the existing utility. In this circumstance, the Panel is [sic] also finds that the LTRP filing previously directed for the utility includes NEFC." (p. 71).

D. Given B.C.'s Energy Objectives and City of Vancouver targets, Creative Energy's LTRP focusses on cost-effective options to reduce greenhouse gas (GHG) emissions for existing customers, including committed customers in NEFC. Creative Energy's preferred solution is the Fuel Switch Project. This project would involve building a new baseload low-carbon steam plant on False Creek Flats which would use clean urban wood waste to produce steam. The existing plant would

continue to be required for peaking and back-up.

E. The Creative Energy LTRP analyzes the external regulatory, policy and planning environment within which Creative Energy is required to develop the Fuel Switch Project. The Creative Energy LTRP also compares the cost-effectiveness of the Fuel Switch Project with the status quo, other project alternatives, and other low-carbon energy benchmarks.

F. Although the Fuel Switch Project represents the least-cost strategy for significant GHG reductions within the existing steam system, there are currently no formal requirements or financial incentives (beyond the current carbon tax) for GHG reductions by existing buildings in Vancouver. Given the low embedded costs of service, low natural gas prices, and fixed carbon taxes, there is a premium to supplying low-carbon energy to existing steam customers. In the absence of enabling mechanisms that reduce the Fuel Switch Project rate impacts, the investment risks for the Fuel Switch Project are not acceptable to Creative Energy.

G. The Fuel Switch Project remains Creative Energy's preferred district-scale alternative for reducing GHG emissions for existing steam customers. The LTRP includes an action plan that identifies the enabling mechanisms that Creative Energy intends to pursue for the next two years to advance the Fuel Switch Project. If sufficient enabling mechanisms can be secured, Creative Energy will file an Application for a Certificate of Public Convenience and Necessity for the Fuel Switch Project. In the event Creative Energy does not secure sufficient enabling mechanisms in the next two years and/or the project is no longer viable for other reasons, Creative Energy proposes a contingency plan that would see it continue to rely on its natural gas plant, and offer individual customers the option to purchase steam produced with renewable natural gas (RNG) if available.

H. Section 44.1(5) of the UCA provides that the Commission may establish a process to review a long-term resource plan.

I. The Commission determined that a **[NTD: to be completed by Commission]**

J. The Commission has reviewed and considered the Creative Energy LTRP and the evidence submitted through the review process.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

NOW THEREFORE the Commission, for the reasons set out in the decision, orders as follows:

1. The Commission accepts the Creative Energy Long-Term Resource Plan to be in the public interest pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA).

DATED at the City of Vancouver, in the Province of British Columbia, this XX day of XXXX, 2016.

BY ORDER

Original Signed By:

Panel Chair/Commissioner

Attachment