Green Energy Projects and Utilities:

An Investment and Governance Guide
for BC Local Governments and First Nations

Volume 2:
Case Studies in Financing and Ownership of Clean Energy Solutions

Prepared by

Community Energy Association

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About This Guide

The *Green Energy Projects and Utilities: An Investment and Governance Guide for BC Local Governments and First Nations* (Volumes 1 & 2) has been created to provide information and analysis on financing and implementing green energy to rural communities and First Nations throughout the Mountain Pine Beetle epidemic zone to help these communities identify and develop local green energy opportunities.

The guide is presented in two volumes:

- Volume 1: *Making Investment and Governance Decisions*
- Volume 2: *Case Studies in Financing and Ownership of Clean Energy Solutions*

For the purposes of this guide, a green energy **project** is one where green power or heat is generated for local government or First Nations facilities or where the project is specific to one building or set of related buildings and there are no additional customers or billing. A green energy **utility** is one where green power or heat is distributed to buildings external to the project and/or a utility has been established to bill for that service.

Volume 1 of the guide (*Making Investment & Governance Decisions*) introduces the reader to the green energy systems (stages, integration and motivation) and provides detailed information to support decisions about ownership and operation, legal and financial considerations and public engagement.

To develop **Volume 2** of the guide (*Case Studies in Financing and Ownership of Clean Energy Solutions)*, fundamental information was captured for 38 green energy projects or utilities located throughout the province. (Appendix A.) Projects on the list were evaluated and a total of 13 projects and utilities selected for detailed case studies. To be included in Volume 2, a project or utility must have:

- had some involvement from either a local government or First Nations,
- been operational and considered 'successful,'
- been willing to contribute to the case study by providing detailed information, including financial information, and
- been a good representation of project type.

Case studies are provided for each of four ownership categories: Privately Initiated, Joint Venture, Full Ownership and Full Ownership with Contracted Operation. Each case study summarizes energy system attributes, governance structure and system financing and provides some detailed information on system development and lessons learned.

Introduction

Green energy systems are comprised of either heating or electricity systems or sometimes both (co-generation). Both heating and electricity systems can exist at multiple scales from individual buildings to neighborhoods or, in the case of electricity, industrial scale operations. Different frameworks are applied at each scale, as outlined in the graphic below.

Heat & Cooling		Electricity

Building to neighborhood	Scale	Building to industrial
• District Energy • Distributed Utility • Individual	Structures	• Net Metering • Distributed Generation • IPP/CPP

At the building scale (project in the parlance of this guide), decisions on ownership and governance are relatively simple. Moving to neighborhood, or larger, scales involves more complex ownership, risk management, governance and financing questions. A summary of the key ownership structures and their relative strengths is provided below.

Legend: Community = First Nations or Local Governments, Color coding: green=good, red=poor, yellow=moderate

Consideration	Community Department	Community Company	Private	Joint Venture / P3
Financial				
Access to capital – initial build				
Access to capital – expansion				
Cost of borrowing				
Non-tax revenue source				
Access to grants				
Local government financial risk				
Can withstand years of losses				
Ability to capture offsets				
Operational				
Technical expertise				
Operational flexibility				
Admin and monitoring scale				
Insulation from operating risk				
Alignment with public interest				
Simplicity				
Complexity of structure				
Overall simplicity for LG/FN				
Other				
BCUC regulation burden				
Transparency of rate setting				
Limits political interference				
Political risk				

Considerations for Community Energy Investment

The table below summarizes considerations noted by case study participants as well as those uncovered through research for this guide.

Case Study participants recommendations	Additional recommendations from research
✓ Solution developers have emphasized the importance of leadership, communication and accountability. Partnerships and good relationships between partners are key. Project leads should stand firm on essential program elements, but be flexible otherwise. ✓ Local capacity and experience, including local suppliers, is an advantage for any project. Local fuel sources lead to economic benefit but making sure fuel sources are reliable is absolutely essential. ✓ Do your homework, but don't overdo it. While feasibility studies are essential, they cannot predict everything. Several participants noted that both good and bad luck on timing had significant impacts on projects. ✓ When dealing with multiple funding partners, hitting milestones can be challenging. Subsidies and incentives have been essential to all projects profiled. ✓ Develop an informed, confident community, especially youth members. Projected profits can be very good at convincing council to take a risk but setting customer rates is complex. ✓ Project scale affects both affordability and benefits. Scalability – the ability to expand a system in the future – is essential. Often one successful project leads to another. ✓ Both developing and operating a system involves steep learning curves. ✓ It is important to conserve energy first and innovate second.	✓ The business model includes a large initial capital cost followed by years of losses before profitability is achieved. An energy utility is a long-term play. ✓ Return is typically linked to risk. Not all investments share the same risk; some will earn more return. ✓ Local governments in BC have access to low cost debt through the Municipal Finance Authority but this comes with strict borrowing limits (25% of previous year's revenue) which can limit the size of the utility and the ability to expand in future years. ✓ Ownership structure of the utility can affect tax treatment which can be the difference between a utility that is viable and one that is not. First Nations and Local Governments do not pay the same income tax as private sector companies. ✓ Ownership is not a decision that can be put off until the end. Some grants will require certain ownership structures and utilities offering to pay for the cost of initial studies will often require an exclusive right to develop the system if it is viable. ✓ Set aside more time than you think you'll need for public consultation, particularly if combustion is involved. ✓ If there is a need for multiple equity partners, consider a limited liability partnership as the corporate structure to more clearly insulate parties from risks and to take advantage of any profits being taxed in the hands of the partners rather than the company. Electricity generation is the most common type of utility requiring multiple equity partners. ✓ If multiple energy utilities are being contemplated or if there is a desire to further insulate the utility from local political shifts, consider establishing a development corporation to be the entity that negotiates and holds the equity positions in the partnerships. ✓ Seek professional tax, business, and legal advice when considering establishing an energy utility or project. ✓ Energy Service Companies (ESCOs) will write performance contracts to eliminate risk on energy utilities…for a price.

Lessons Learned

The following list summarizes key lessons learned from interviews with those involved with, or directly responsible for, each of the 13 case studies in this guide.

1. Conserve energy first; consider new supply and innovative energy solutions second.

2. Leadership, communication, accountability and good relationships between partners are critical. Project leads should stand firm on essential program elements and be flexible otherwise.

3. Local capacity and experience, including equipment suppliers, provide an advantage for any project. Local equipment suppliers can sometimes offer reduced prices and local fuel sources can deliver economic benefit. In all cases, ensuring that fuel sources are reliable is absolutely essential.

4. Do your homework, but don't overdo it. While feasibility studies are essential to getting started, they cannot predict everything. Several case study participants noted that both good and bad luck on timing had significant impacts on projects, particularly in relation to market downturns and upturns.

5. When dealing with multiple funding partners, hitting milestones during project development can be challenging. Subsidies and incentives have been essential to almost all projects profiled, however, identifying relevant programs is difficult and programs tend to come and go.

6. Develop an informed, confident community and include youth members in consultation.

7. Project scale affects both affordability of the system and extent of benefits. Scalability – the ability to expand a system in the future – should be taken into consideration. Often one successful project leads to another. Projected profits can help increase community comfort about risks.

8. Developing and operating a system both involve steep learning curves for staff. Local sources of expertise are a significant benefit. Setting customer rates is complex.

Supporting Privately Initiated Projects

A local government or First Nation can support a private initiative by publicly acknowledging support for the project, expediting approval processes, assisting with public engagement and agreeing to connect public facilities to the system.

Consideration	Supporting a Private Initiative vs. Joint Venture or Full Ownership
Financial	
Access to capital – initial build	**Not required**
Access to capital – expansion	**Not required**
Cost of borrowing	**None**
Non-tax revenue source	**No**
Access to grants	**Not required**
Local government financial risk	**None**
Can withstand years of losses	**No:** Local governments and First Nations should have a back-up plan for connected facilities in case the private utility goes out of business.
Ability to capture offset attributes	**Possible**: Capturing offsets possible under both joint venture and full ownership but only if the private developer/operator explicitly assigns environmental benefits to your organization. Also, be sure to read the fine print in grant applications. Most contracts with utilities will assign environmental benefits to the utility. Note that offsets generally are only applicable to heat generation or remote (off-grid) electrification.
Operational	
Technical expertise	**Improved:** Private developers/operators have broad experience in renewable energy implementation
Operational flexibility	**None**
Admin and monitoring scale	**None**
LG/FN insulation from risk	**Improved:** Still some risk if private operator goes out of business
Alignment with public interest	**Reduced:** Public interest is limited to local benefits from the project (such as economic development)
Simplicity	
Complexity of structure	**None**
Overall simplicity for LG/FN	**Improved** A trusted private sector developer can run with a project, reducing the need for local government or First Nation decision making
Other	
BCUC[1] regulation	**Increased:** Private utilities must get approval from the Commission; this does ensure reasonable rates.
Transparency of rate setting	**Neutral:** Local rate setting is transparent; BCUC rate setting is transparent
Limits political interference	**Neutral:** Political interference may occur during project proposal stage but will be reduced later
LG/FN political risk	**Reduced:** Financial risk is almost completely reduced; still some risk if private operator goes out of business.

[1] In British Columbia, public utilities are regulated by the BC Utilities Commission (BCUC). The BCUC establishes, amongst other things, the rates that can be charged to utility customers.

Case Study #1: Fink Enderby District Energy Utility

System Overview	
Community: Enderby	**Population:** 2,900
Owner: Fink Machine Inc.	**Operator:** Fink Machine Inc.
Year Started: 2011	**Connections:** 8 current customers
Generation Source: Biomass – local sawmills, diverted wood waste and local businesses	
Generation Technology: Viessmann KOB Pyrot 540 kW wood-fired boiler with back up 300 kW gas-fired boiler.	
Generation Capacity: 540 kW	
Energy Produced: Heat √ Electricity x	
Distribution System: Urecon Insulated Pex Line (3 inch main) for district loop of 640 metres	

System Governance	
Venture Partners	No
Operating Agreements	No
Other Investment Sources	Financed, owned and operated by Fink
Rate Setting/Project Oversight	Basic utility contracts with customers
Billing Method	On-line billing. Monitored by Schneid Control System
Legal Structures	N/A

System Financing

Phase	Cost	Funding
Planning	Minimal: technical evaluation	Privately funded
Construction	$1.2 Million	Privately funded
Operation	$8,000/yr	$60,000/yr. average operating revenue

1. Background

Fink Machine Inc. received approval from the City of Enderby in May 2011 to install the privately financed, owned and operated Fink Enderby District Energy System, which provides space heating, domestic hot water and pool heating to the community. The first system customer was the City of Enderby, who connected their outdoor pool to the system.

Fink Machine will supply carbon neutral renewable energy from wood biomass to 12 individual customers. The underground grid supply line is 640 metres long. The district energy system, a private utility under 1 MW, is the first of its kind in western Canada; however, biomass systems of this kind are common in Austria.

2. Cost/Benefit

Private funds were used to evaluate feasibility of the system, which included as assessment of energy cost and consumption, type of buildings and building heat loss.

District heating lines were installed at $400/metre. Total cost of this system was around $1.2 million. This is an affordable system that has changed the dynamics of the industry. Payback is around ten years providing that all anticipated customers are on-line.

3. Governance

The system is owned and operated by a private utility. City of Enderby senior staff and Council embraced the proposal by Fink Machine and helped expedite the process. Time from concept to operation was less than two years. Representatives from Lumby, Vernon and Peachland have visited the Fink Enderby

District Energy System and are now considering this form of renewable energy and all the benefits it brings to the local economy.

Fink Machine has basic utility contracts arranged with customers. A Schneid control system measures flow and bills customers accordingly. Fink Machine provides training at the time of system connection and ongoing support when needed. Interaction with the system is computerized and billing is on-line.

4. Operation

A Viessmann Pyrot KRT-540 kW wood-fired boiler is the system's primary source of space heating, domestic hot water and pool heating. The fully-automatic Pyrot achieves efficiency of up to 85% while minimizing emissions. A 300 kW gas-fired boiler provides backup and additional capacity during peak loads. A custom-built timber frame boiler house includes a district fuel bunker with a capacity of 50 tonnes, which allows two 53-foot trailers to unload simultaneously. An automated walking floor delivers fuel from the storage bunker to the Pyrot's feed auger. When fuel gasification and combustion are complete, an automated de-ashing system extracts ashes from the combustion chamber and transfers them to a bin. An ash removal auger extracts the ashes into a large external container once they have cooled. The Pyrot boiler feeds an 8,400 L water buffer tank before distributing heated water to transfer stations and customers through a 640 metre main line consisting of three-inch insulated Urecon PEX pipe.

Wood biomass fuel is supplied by local sawmills, wood product manufacturers and wood waste diverted from landfills and businesses within a two hour radius. Area landfills are now modifying their material recycling facilities to separate wood biomass fuel. Once fully operational, the system is expected to consume 800 tonnes of renewable wood fuel annually while helping to mitigate approximately 425 tonnes of greenhouse gases. Customers save 10-18% on utility bills, resulting from improved heating efficiency and avoiding payment of the carbon tax (reducing costs by 10-12%). They also no longer need to purchase or repair their own heating systems.

5. Lessons Learned

- Biomass district energy systems are not overly complicated in terms of design.
- Replicating the system in different communities using Enderby as a benchmark will provide cost savings on system design.
- It is important to monitor work being performed by contractors and subcontractors so that costs stay in line.
- Ensure that the boiler room is built large enough to support system expansion.
- Communities who are updating utility lines should consider installing district energy infrastructure at the same time, eliminating the cost of retrenching and reducing system costs further.
- Fink Machine has demonstrated that a biomass district energy system can be installed and operated effectively for less than $1 million in an area where natural gas is a preferred fuel. The project has set a new benchmark for biomass district energy systems. Smaller communities in particular may benefit from avoiding the high costs of detailed technical and economic feasibility studies.

6. Sources and Links

Interview with: Stephen Bearss, Renewable Energy Representative, Fink Machine Inc.

Photo credit: C. Bearss, Imedge Photography

Choosing a Joint Venture Approach

Like other infrastructure development projects, developing green energy projects and utilities comes with a package of risks that must be borne by developers, owners and operators. When considering which type of ownership approach to use, key considerations are how to identify and properly offset these risks, and how to finance the capital costs of the project.

The purchase of capital required for green energy projects and utilities can be financed via debt financing, government grants and/or by selling *equity* in a project. Equity represents the dollar value of an ownership interest in a project or utility and it can be sold to raise the funds required to develop green energy infrastructure. Joint ventures are one way to bring equity to a project.

A joint venture is a commercial enterprise undertaken jointly by two or more parties who otherwise retain their separate identities. In a joint venture, partners choose to develop a new entity and new assets by contributing financially to a project over a specified time period. Partners exercise control over the enterprise and can choose to share profits, revenues, expenses and/or assets. A project may begin as a joint venture but either partner may buy or sell their interest after an agreed upon time period or if objectives change, as long as contracts and agreements have a buy-out clause or can be amended.

A *green energy project* generates green power or heat for local government or First Nation facilities and is often specific to single or small group of buildings. There is a single consumer, and no external customers. A *green energy utility* distributes green power or heat to buildings external to the project. Usually a formal utility is established to bill for energy consumed. Joint ventures are well suited to electricity generating projects and utilities because of the very high capital costs of these projects. It is less common to use the joint venture approach to building-scale projects or district energy (heat) projects and utilities.

Developing a green energy project or utility involves risks at all major stages – financing, construction, and operation. Operational risks include meeting regulations, oversight on energy pricing and changes in demand (energy market) or fuel supply prices. Legal aspects joint ventures are about managing risk to the project and to the people behind it. Projects and utilities may be exposed to contract liability (arising from a party's failure to fulfill commitments made in a contract), tort liability (arising between parties without a contractual relationship, including negligence and nuisance), and regulatory liability (arising because a party engages in actions that are specifically prohibited by law or fails to perform actions that are specifically required by law).

The table below compares joint ventures to full ownership for a range of financial, operational, management and regulatory considerations related to green energy projects and utilities.

Consideration	Summary: Joint Venture vs. Full Ownership
Financial	
Access to capital – initial build	**Improved:** Profitable joint ventures will have access to local government and First Nation sources as well as private sources
Access to capital – expansion	**Improved:** Profitable joint ventures will have access to local government and First Nation sources as well as private sources
Cost of borrowing	**Neutral:** Interest rates available to local government or First Nation unchanged
Non-tax revenue source	**Possible:** If the utility is profitable. Expect that years or decades will be required before capital debt is paid down and the entity is profitable. Note that rate-payers may view excessive rates as indirect taxation.
Access to grants	**Improved:** Access to grants can be improved if other sources have been leveraged
Local government financial risk	**Reduced**: Joint ventures are a good way to transfer risk to experienced private utilities or ESCOs
Can withstand years of losses	**Improved**: Private partners have larger portfolios and are better able to absorb losses
Ability to capture offset attributes	**Possible**: Capturing offsets possible under both JV and full ownership but only if the JV contract explicitly assigns environmental benefits to your organization. Also, be sure to read the fine print in grant applications. Most contracts with utilities will assign environmental benefits to the utility. Note that offsets generally are only applicable to heat generation or remote (off-grid) electrification.
Operational	
Technical expertise	**Improved:** Private partners have broad experience in renewable energy implementation
Operational flexibility	**Neutral:** In some cases, greater local government or First Nation control can increase the ability to be responsive to local conditions. In other cases, private sector control can increase access to solutions to operational difficulties
Admin and monitoring scale	**Improved:** A joint venture may have benefits over full ownership if the private sector partner is involved in multiple utilities and has established central monitoring, customer care, and back-office (billing, accounting, IT) to support multiple utilities.
LG/FN insulation from risk	**Improved:** Private partners have broad experience in renewable energy implementation
Alignment with public interest	**Reduced:** Greater local control of the resource means that benefits stay local
Simplicity	
Complexity of structure	**Increased:** Greater complexity of structure requires more resources and expertise upfront (and sometimes longer timelines) to structure a project
Overall simplicity for LG/FN	**Neutral:** Full ownership may reduce the need for extensive consultation and agreements, but at the same time a trusted private sector partner can run with a project, reducing the need for local government or First Nation decision making
Other	
BCUC regulation	**Increased:** Private utilities must get approval from the Commission; this does ensure reasonable rates.
Transparency of rate setting	**Neutral:** Local rate setting is transparent; BCUC rate setting is transparent
Limits political interference	**Neutral:** Political interference may occur while choosing partners and establishing agreements but will be reduced during construction and operation
LG/FN political risk	**Reduced:** Financial risk is significantly reduced

The principal **advantages** of this model are:

- Risks are shared with private-sector partners
- Capital costs are shared
- Project design, implementation and operation can benefit from private sector expertise

Balanced against these benefits are **disadvantages** such as loss of some control of the project and loss of some revenues to the private partner. Reduced control over the project may make it more difficult to ensure that the project meets specific local needs (such as subsidizing the utility rate to encourage connection or contracting with local sources for fuel or maintenance).

When considering a joint venture project or utility, local governments and First Nations should be aware that:

- Private sector partners will want to ensure a profit and may want a substantial share of other financial benefits.
- Each partner may have a different vision and set of goals for the project.
- Agreements will be needed to describe the terms of the partnership and mechanisms will be required to protect against liability.
- Joint ventures are more challenging to manage and coordinate and, at least in the beginning, more time consuming to set up.
- Joint ventures require financial and legal consultation when establishing agreements and contracts.
- A joint venture project will be at greater risk if it does not show profit.
- Not all partnership arrangements will be able to access Municipal Finance Authority (MFA) financing or financing specific to First Nations. Local governments and First Nations should contact any financing authorities before establishing any agreements.

Partial ownership can take many forms. In some cases, it is possible for a local government to own only some system assets, but to wholly own these. For example, a local government could own the distribution system in a district heating system, while a private partner might own the heat generators. Alternatively, partial ownership can mean that both local government and private investors hold equity in the project. This model will usually involve establishment of a subsidiary corporation.

When creating green energy utility joint ventures, it is important to remember that BC Utilities Commission (BCUC) oversight may be required. While some joint ventures may not require oversight, a legal opinion should be requested early on by the partners to confirm any exemptions on a case-by-case basis.[2]

More detailed information on types of joint ventures and considerations for creating them can be found in Volume 1 (*Making Investment and Governance Decisions*).

[2] In British Columbia, public utilities are regulated by the BC Utilities Commission (BCUC). The BCUC establishes, amongst other things, rates that can be charged to utility customers.

Case Study #2: Canoe Creek Run of River

System Overview	
Community: Tla-o-qui-aht First Nation	**Population:** 1,000
Owner: Canoe Creek Hydro (Tla-o-qui-aht First Nation & Swiftwater Power Corp.)	**Operator:** Barkley Project Group Ltd.
Year Started: 2010	**Connections:** BC Hydro grid
Generation Source: Hydroelectric power	
Generation Technology: Run of river hydro project	
Generation Capacity: 5.5 MW	
Energy Produced: Heat X Electricity √	
Distribution System: Electricity sold to BC Hydro under long term contract	

System Governance	
Venture Partners	Limited Partnership: Tla-o-qui-aht First Nation and Swiftwater Power Corporation
Operating Agreements	40 year Electricity Purchase Agreement with BC Hydro
Other Investment Sources	Nuu-chah-nulth Economic Development Corporation Western Economic Diversification Canada.
Rate Setting/ Project Oversight	Canoe Creek Hydro. BC Hydro and Province provide conditional water license and permit to construct.
Billing Method	All power sold to BC Hydro at fixed price.
Legal Structures	First Nations Government; Limited Partnership; Electricity Purchase Agreement

System Financing

Phase	Cost	Funding
Planning	$ 1M in pre-development	ecoENERGY for Aboriginal and Northern Communities; ecoENERGY for Renewable Energy; Aboriginal Business Canada.
Construction	$14,000,000 (includes $1.5 M in financing costs)	Nuu-chah-nulth Economic Development Corporation, Western Economic Diversification Canada.
Operation	Not public	Not public

1. Background

Formed as a partnership between Tla-o-qui-aht First Nation and Swiftwater Power Corporation, Canoe Creek Hydro produces energy from a run-of-river project. Canoe Creek hydro is jointly owned by Tla-o-qui-aht First Nation, located in Tofino, and Swiftwater Power Corp. The project is managed by Barkley Project Group.

Renewable energy, along with sustainable forestry, ecotourism and fisheries, is part of the Tla-o-qui-aht First Nation's vision of sustainable resource management. Significant environmental planning and research was conducted to ensure that the utility was constructed and operated in a way consistent with the community's sustainable development ideals. This included ensuring that the Kennedy River watershed, within which the Canoe Creek project is located, and surrounding wildlife habitat is protected. The Canoe Creek Hydro facility received environmental certification under the EcoLogo Program and the Clean Energy Association of BC presented Canoe Creek Hydro Company with the 2010 Project Excellence Award.

2. Cost/Benefit

Run-of-river projects of 1-10 MW in size typically take three to five years to move from concept to construction and an additional two years to begin operation. The time and effort required to gain regulatory approval accounts for a significant portion of total costs. Completing the environmental impact assessment, hydrological and engineering studies and collaborating with BC Hydro cost between $750,000 and $1.5 million. ecoENERGY for Renewable Power, ecoENERGY for Aboriginal and Northern Communities programs and Aboriginal Business Canada together provided $1million in funding for a business plan, environmental impact assessment and interconnection study. The total cost of construction for Canoe Creek was around $14 million, including financing costs of $400,000, staff time, fees for financing and interest paid during construction.

BC Hydro electricity purchase agreements pay a fixed price for a term between 20 to 40 years, significantly reducing market risk. This is enough power for about 2,000 homes. Canoe Creek's return on investment target is 10-15% and anticipated payback on equity is 5-10 years. The project will reduce GHG emissions by approximately 9,000 tonnes each year.

3. Governance

The Canoe Creek hydro project is an important step towards financial self-sufficiency for Tla-o-qui-aht First Nation. It is also a very deliberate investment in an energy project that will not deplete natural resources. The Tla-o-qui-aht First Nation hopes to stay true to its vision of sustainability while fostering economic development within its community. Their ultimate goal is to reinvest the profits from the Canoe Creek hydro project into other economic and social development programs, including rebuilding dwindling salmon stocks in the area and exploring other ways to generate clean energy.

4. Operation

In June 2010, Canoe Creek secured a 40-year electricity purchase agreement with BC Hydro. Canoe Creek now generates 5.5 MW of energy, enough to power approximately 2,000 homes. The cost of generating electricity is about 5-20 cents/kWh. Minimum flows of 0.5-12 m^3/s off grid are required.

5. Lessons Learned

- Having a Chief and Council committed to the project from beginning to end is critical.
- Develop a relationship with a joint venture partner that you trust and stick with it. Their expertise will be required to move quickly. Make sure they're experienced and committed to the project.
- Support from Aboriginal Affairs and Northern Development Canada and the solid partnership with Swiftwater Power Corporation were both key to project success.
- Access to financing can be challenging – in this case it took almost a year because of the poor credit climate during the search for financing.
- Success is dependent on stream flow. Water allocation decisions require water for fish before allocating water for hydro power.
- Proximity of potential load and existing grid is key because cost of transmission is an important factor.

6. Sources and Links

- Aboriginal Affairs and Northern Development Canada
- Barkley Project Group
- Canoe Creek INAC Brochure

Interview with: Iain Cuthbert, President Canoe Creek Hydro.

Photo credit: Canoe Creek Hydro (Barkley Project Group)

Case Study #3: Heat Recovery Project at Juan de Fuca Pool Recreation Centre

System Overview	
Community: Capital Regional District	**Population:** 70,000
Owner: Capital Regional District, Juan de Fuca Electoral Area and municipalities of Colwood, Langford, Metchosin, Highlands and View Royal	**Operator:** West Shore Parks and Recreation Society.
Year Started: 2000	**Connections:** Three civic buildings
Generation Source: Heat recovery	
Generation Technology: Heat exchanger takes heat from refrigeration system and air handler returns waste heat (warm air) to pool	
Generation Capacity: Quantity of heat recovered: 700,000 BTU's per hour	
Energy Produced: Heat √ Electricity x	
Distribution System: Glycol loop moves waste heat to the pool and natatorium air handling unit.	

System Governance	
Venture Partners	West Shore Parks and Recreation Society is A partnership of Colwood, Langford, Metchosin, Highlands, View Royal and Juan de Fuca Electoral Area.
Operating Agreements	No
Other Investment Sources	No
Rate Setting/Project Oversight	Not required.
Billing Method	N/A
Legal Structures	Co-owners Agreement; Members Agreement; Operating, Maintenance and Management Agreement.

System Financing

Phase	Cost	Funding
Planning	-	-
Construction	$550,000	Reduced natural gas consumption by $50,000/yr.
Operation	-	-

1. Background

The West Shore Parks and Recreation Society (WSPRS) serves the Vancouver Island communities of Langford, Colwood, View Royal, Metchosin and Highlands and a Capital Regional District Electoral Area. The Society's Board of Directors is made up of elected officials and community representatives from each community. In 1999, the Society recognized that the existing Centennial Pool needed significant upgrades. Recovering heat from the arena and rink and using it to heat the new aquatic facility was determined to be a better option than using gas fired equipment. The new Juan de Fuca Pool was opened in 2000. Heat recovery units in pool air handling units recycle heat, which is then upgraded and pumped back into the facility. This improvement has lowered heating costs and decreased the humidity in the pool area.

2. Cost/Benefit

In round figures, the cost of gas fired equipment for heating the pool was approximately $225,000 and the cost of heat reclamation equipment was $325,000. Using heat reclamation equipment reduced natural gas consumption by about $50,000 per year. Because the new pool was larger than the old pool, payback on the incremental cost difference of the equipment is about two years. The incremental cost difference between the proposed gas fired equipment versus the heat reclamation equipment was $100,000.

3. Governance

The West Shore Parks and Recreation Society (WSPRS) operates with an annual budget of just under $13 million. About 55-60% of revenues each year are generated from user groups with the balance provided by municipal taxes. The members of the WSPRS have agreed to co-manage their capital assets via a capital planning process. Several agreements guide ownership of facilities and land between WSPRS members. A members' agreement, originally written in 2001, governs each member's obligations as participants in the WSPRS to provide parks and recreation services through a contract with the Society. The *Operating, Maintenance and Management Agreement*, which is binding between the WSPRS and the member municipalities, outlines responsibilities of the Society to operate, maintain, supervise and manage all aspects of the facilities and programs. Finally, the *Co-Owners Agreement* facilitates joint ownership of the lands. It also specifies that management of activities can be contracted out to an owner's representative, which is currently the West Shore Parks and Recreation Society.

4. Operation

Heat is recovered from the Juan De Fuca Arena and Curling Club and then used to heat the air in the swimming pool area. A heat exchanger in the ammonia plant transfers heat to a glycol system, which then transfers it to the air handling unit for the natatorium. The capacity of heat that can be recovered is approximately 700,000 BTU's per hour. Approximately 20% of the heat available from the arena and curling club is being recovered, so there are plans to install heat exchangers with a greater capacity in order to transfer all of the available heat to the natatorium air handling unit.

The heat exchanger was sized for full capacity of one compressor (there is usually always at least one running), which is about 10% more than what was actually needed to handle the pool load on the coldest days. In addition, in 2011, a heat pump was added to the pool exhaust system. The heat pump upgrades waste heat from the pool to a higher temperature and inputs it into the pool, and also into the natatorium air handling unit, further reducing the need for natural gas.

If a district energy sharing loop was added to the system, it would optimize the function of the heat exchanger, producing waste heat to be used elsewhere in the community.

5. Lessons Learned

- Electrically driven refrigeration equipment is the highest ongoing non-labor cost of facility operation.
- The entire refrigeration process is devoted to removing heat from the ice and disposing it outdoors via a condenser. It makes economic sense to harness this waste heat. Benefits include drastically reduced facility operating expenses, increasing refrigeration system operating efficiencies and reducing dependence on fossil fuels.
- There is generally a very quick payback on first costs and some rebates are available. Leasing equipment can reduce costs and provide an immediate positive cash flow.

6. Sources and Links

- *West Shore Parks and Recreation Society Facility Capital Plan*, 2011

Interviews with:

- Wade Davies, Manager of Operations, West Shore Parks and Recreation.
- Art Sutherland, Project Management and System Design, Accent Refrigeration Systems

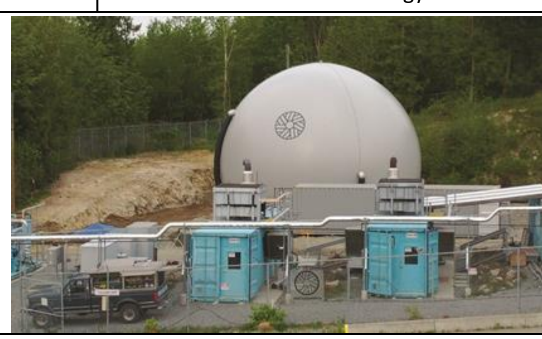
Photo credit: Accent Refrigeration

Case Study #4: Nanaimo Bioenergy Centre Project

System Overview	
Community: Regional District of Nanaimo	**Population:** 150,000
Owner: Cedar Road Bioenergy Inc.	**Operator:** Cedar Road Bioenergy Inc.
Year Started: Phase I March 2009; Phase II to be complete in 2014	**Connections:** BC Hydro grid
Generation Source: Landfill gas	
Generation Technology: Gas utilization technology at landfill site (waste to energy).	
Generation Capacity: 1.4 MW	
Energy Produced: Heat X Electricity √ Future Phases: Heat and Transportation Fuels	
Distribution System: Connected to BC Hydro grid	

System Governance	
Venture Partners	Cedar Road Bioenergy Inc. (CRB); Regional District of Nanaimo (RDN); BC Bioenergy Network (BCBN)
Operating Agreements	CRB and BC Hydro Energy Standing Offer & Electricity Purchase Agreement CRB /RDN Development and Operation agreements: 20% of net profits to RDN Collaborative Development and Demonstration Agreement: RDN, BCBN, CRB
Other Investment Sources	Senior bank debt $1.7 million Community Futures debt $225,000 Debenture debt $1,100,000 BC Bioenergy Network (BCBN) Phase I $400,000 loan; Phase II $200,000 equity Cedar Road Bioenergy Inc. $375,000 equity Federation of Canadian Municipalities: Provided 50% of the cost of constructing the collection and flare system (2003-2005) in exchange for ownership of the carbon credits.
Rate Setting/ Project Oversight	Phase I: standing offer program, BC Hydro 20 year electricity purchase agreement. Phase II: transportation fuel and thermal heat not commissioned or contracted yet.
Billing Method	N/A – metered through BC Hydro grid and fuelling stations
Legal Structures	Owner / Operator Cedar Road Bioenergy Inc. with partners in collaboration for development and demonstration Non-binding Collaborative Agreement between Regional District of Nanaimo, Cedar Road Bioenergy Inc. and the BC Bioenergy Network. Development and operating agreements between RDN and Cedar Road Bioenergy.

System Financing		
Phase	**Cost**	**Funding**
Planning	Phase I: $500,000 Phase II: $100,000	
Construction	Phase I: $3.8 Million Phase II Budget: $2.3 Million	Phase I: $3.4 M combined debt and equity; $400,000 BC Bioenergy Network Phase II: $1.0 M Innovative Clean Energy Fund grant; $200,000 BC Bioenergy
Operation	Annual operations and maintenance $600,000, including debt interest repayments.	Annual Revenue Phase I: $450,000 in 2011 Annual Revenue Phase II: $400,000 projected in 2014



1. Background

The Regional District of Nanaimo (RDN) represents four municipalities and seven rural electoral areas located in the centre of Vancouver Island. The RDN's 17-member Board of Directors delivers solid waste management services on a cooperative basis to the region and selected local areas. Cedar Road

Bioenergy Inc. (Cedar Road) is a clean energy company that specializes in harvesting methane from landfill gas and converting it into useable energy.

In 2005, Cedar Road and the Regional District of Nanaimo entered into a public-private partnership to establish a landfill gas utilization system, which would build on the collection and flaring system established by the RDN in 2003. The first of its kind to focus on small to medium landfill sites, Phase I of this project uses methane from a landfill to generate electricity. Other applications are planned for future phases. Subsequent investment and support from the BC Bioenergy Network led to the establishment of a collaborative development and demonstration facility, known as the Nanaimo Bioenergy Centre. This centre allows technology suppliers, local governments and other stakeholders to identify best practices for landfill gas-to-energy projects at small to medium landfill sites.

2. Cost/Benefit

In 2002, RDN completed a landfill gas utilization study with financial assistance ($29,460) from the Federation of Canadian Municipalities (FCM). In 2003, the RDN Board of Directors awarded a tender to construct an aggressive landfill gas collection and flare system that would provide sufficient gas to support the use of landfill gas as a green energy source. FCM cost-shared 50% of this $1.3 million project in exchange for the transfer of any emission reduction rights (carbon credits) arising from the project.

In 2005, following a Request for Proposals process, the RDN Board approved development and operating agreements with Cedar Road Bioenergy Inc. to provide for the design, construction and operation of a facility on the RDN landfill to generate electricity using landfill gas as an alternative fuel source. From 2006 to 2009, the RDN Board approved four amending agreements to the development and operating agreements with Cedar Road Bioenergy to respond to various changes with respect to the project schedule and other requirements.

In 2009, the BC Bioenergy Network provided a $400,000 loan to support the final stages of commissioning the project and contracting with BC Hydro. In 2010, Cedar Road Bioenergy completed construction of the 1.4 megawatt methane-fueled electrical power plant. Cedar Road sells the electricity that is generated to the BC Hydro Standing Offer Program under a 20 year Electricity Purchase Agreement executed in two phases in 2009 and 2010.

A $2.3 million expansion and upgrade of the plant commenced in 2012. In 2012, the BC Bioenergy Network announced a $200,000 equity investment in the plant expansion and a $1 million grant from the BC Government Innovative Clean Energy (ICE) Fund was approved. Implementation support and expertise from partners and stakeholders is a key component to the project success. In mid-2012, Cedar Road Bioenergy commissioned a landfill gas storage facility on site which is substantially improving project efficiency and economics. Throughout 2012-2015, the Nanaimo Bioenergy Centre will accommodate third party innovative demonstration and test platforms.

The return on investment is 6%, subject to biogas supply projection increases. Greenhouse gas emission reductions in 2011 were 28,113 tonnes.

3. Governance

This project is based upon a) a public private partnership between the RDN and Cedar Road Bioenergy Inc. and b) a non-binding Collaborative Development and Demonstration Agreement. To help disseminate best practices to other small-to-medium-sized landfills, the original Collaborative

Development and Demonstration Centre (CDDC) partnership has now expanded to include the Union of British Columbia Municipalities and another small-to-medium-sized municipality, the Regional District of Fraser Fort George. The project falls under the BC Ministry of the Environment's Landfill Gas Management Regulation, which became effective in 2009, establishing province-wide criteria for landfill gas capture from municipal solid waste landfills.

Phase II (plant expansion for transportation fuel and thermal heat) investment will support the installation of a gas storage system which will improve the revenues and income for the $4 million facility, paving the way for incremental expansion to improve the integrated bioenergy benefits and energy utilization at the centre. Cedar Road will make royalty payments to RDN equal to 20% of net profit earned.

4. Operation

The equipment cluster utilizes a modular design concept consisting of a gas conditioner and two 633 kW GE Jenbacher generating sets. The equipment can be easily relocated and/or allow for expansion on the current site. The BC Hydro interconnection equipment and landfill methane gas conditioning equipment have been sized for 1.54 megawatts of total electrical output. The facility's eventual generating capacity is planned to be 3 to 5 megawatts within 10 years. Annual operating costs are around $600,000, including debt repayments.

RDN's royalty payment is projected to be between $20,000 - $100,000 annually when the RDN gas supply reaches full output. With present gas flow, RDN will reach the defined net profit structure in 2014, at which time the royalty will begin to be paid, assuming that the gas supply will maintain current levels and/or increase from present levels.

Cedar Road expects to generate $400,000 in additional revenue after plant expansion in Phase II, for an annual revenue increase of $1 million once full output is reached. RDN expects royalty payments to increase from $40,000 annually to over $100,000 annually after Phase II expansion.

5. Lessons Learned

- Strong communication and accountability are important. It is helpful to have a project champion inside local government.
- Local government processes can take some time.
- Solid investment behind the project is necessary to overcome delays.
- Flexibility in contracts/agreements is important so that business plans can shift to reach commercial viability.

6. Sources and Links

Interviews with:

- Sandy Ferguson, Director of Marketing [BC Bioenergy Network]
- Paul Liddy Managing Director [Cedar Road Bioenergy Inc].
- Carey McIver, Solid Waste Manager [Regional District of Nanaimo]

Photo credit: K. Wilson

Case Study #5: Dockside Green Community Energy System

System Overview	
Community: Victoria	**Population:** 84,000
Owner: Dockside Green Energy (DGE) LLP	**Operator:** Corix Utilities
Year Started: 2009	**Connections:** 200 customers now; 1,100 at completion
Generation Source: Biomass (locally sourced, clean urban wood residue)	
Generation Technology: Nexterra biomass gasification process creates syngas for boiler, with 3.4 MW natural gas backup system	
Generation Capacity: Biomass rated capacity of 2 MW – at peak capacity consumes 1.1 tonnes of wood fuel/hour	
Energy Produced: Heat √ Electricity x	
Distribution System: District energy system	

System Governance	
Venture Partners	Vancity, Corix Utilities, Terasen Energy Services (now Fortis)
Operating Agreements	Multi-year contract: Corix Utilities contracted by Dockside Green Energy for operation, maintenance and customer service
Other Investment Sources	Natural Resources Canada, Technology Early Action Measures (TEAM) $1.5 million FCM: Green Municipal Fund $350,000
Rate Setting/ Project Oversight	The British Columbia Utilities Commission (BCUC) governs rates. Corix developed the initial rate design and will review and update it as required by BCUC. Corix will make regular filings to BCUC after approval by DGE
Billing Method	Meter Reading and billing; Customer Service Agreements
Legal Structures	Dockside Green Energy LLP Hydronic Energy Services Terms & Conditions

System Financing

Phase	Cost	Funding
Planning		
Construction	$6.1 M (total development project) $1.5 M (utility only) Total system construction costs, including project management $8.27 M	Natural Resources Canada, Technology Early Action Measures (TEAM) $2.45 million FCM Green Municipal Fund $350,000
Operation	Confidential	Cost savings (building energy needs reduced by 80%)

1. Background

Dockside Green was built on a 15 acre (6.1 ha) brownfield site in Victoria's Inner Harbour. The City, which originally owned the site, required a district heating system (amongst other sustainability innovations) as a condition of sale. The resulting "micro-utility," Dockside Green Energy LLP (DGE), is an investor-owned district energy utility and will be Canada's first urban gasification facility once challenges have been overcome.

DGE is one of 16 founding projects in the Clinton Climate Initiative's Climate Positive Development Program. Currently the biomass gasification plant has more than enough capacity for the development. In the future, if off-site energy sales were increased, the treatment plant could be modified to sell heat to the district energy grid. This would allow the recovery of yet another valuable resource, further offsetting GHG emissions and potentially offsetting costs for utility customers.

2. Cost/Benefit / Finances

Dockside Green secured federal funding to offset some capital costs of the Dockside Green Energy system through Technology Early Action Measures (TEAM). TEAM is primarily led by Natural Resources Canada, Environment Canada and Industry Canada. TEAM funding of $2.45 million was used to offset capital costs of constructing the DGE. A grant from the Federation of Canadian Municipalities was used, amongst other things, to offset regulatory costs, including amendments to the BC Waste Management Act.

Vancity Credit Union provided $20 million in equity to the Dockside Green project and has first right of refusal for financing all buildings and utility systems. Vancity also posted a $25 million guarantee for the project to the City for the various commitments made by the developer. Dockside Green Limited Partnership set aside $1.5 million towards the biomass system with no expectation of return on investment to assist overcoming the barriers of utilizing a central biomass system.

CO_2e savings per year are expected to be 2,361 tonnes when the plant is at full operation.

3. Governance

DGE is a utility established to provide space heating and hot water through joint partnership of Vancity Capital Corp, Terasen Energy Services Inc. (now Fortis), and Corix Utilities. Corix is also contracted by DGE for operation, maintenance and customer service. DGE initially considered entering into a partnership with the City of Victoria to avoid BC Utility Commission (BCUC) regulation, but was advised that partial municipal ownership would still be subject to BCUC jurisdiction.

DGE bills each strata corporation a monthly fee based on the total floor space of the building, measured in square metres, and for the amount of energy used by each strata as measured by the consumption meter located in each building complex. The strata for each building complex in turn charges residents. In-suite meters are owned and operated by the strata.

To keep rates competitive, DGE proposed to:

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

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

4. Operation

The system 'gasifies' biomass to create 'syngas'. Burned in a boiler just like natural gas, syngas will create heat for space and hot water needs for the 1.3 million square feet of Dockside Green's residential, office, retail and industrial space. As of 2012, the system provides heat and hot water to four residential and two commercial buildings. Loads are currently lower than expected and the plant is using natural gas boilers to supply customers.

The system will require only 3,000 tonnes of bone dry waste wood per year, the equivalent of 110 B-train truckloads of wood. Air emissions from the system are 50% below BC's most stringent requirements for particulate matter.

5. Lessons Learned

- The property development market is unpredictable. DGE has experienced several challenges in its first few years of operation. Soft market conditions slowed construction, resulting in lower than forecast loads and revenues. With a much smaller load factor, running the biomass plant was not practical, and the plant has been using the natural gas boilers to supply customers. An expected contract with the Delta Hotel will provide the new load needed to run the biomass system, once a reliable biomass source is found.
- Ensure availability of suitable local wood waste before building the energy plant. The original provider of biomass failed to deliver. DGE continues to seek alternative supply sources, with moisture content, foreign objects, and contaminants (e.g. nails, glue) providing challenges.

6. Sources and Links

- Corix Utilities: Projects – Dockside Green
- D. Ebner, Victoria's District Energy Community a Model for Canada and Beyond, Globe & Mail, November 22, 2011
- *Integrated Resource Recovery Case Study: Dockside Green Mixed Use Development*, BC Ministry of Community, Sport and Cultural Development
- Nexterra Project Profile, *Dockside Green Biomass Gasification System*

Interview with: Kelly O'Brien, Manager Operations & Marketing, Dockside Green

Photo credit: Nexterra Systems Corp (Dockside Green Project Profile) from http://nexterra.ca/files/dockside-green.php

Choosing a Full Ownership Approach

A green energy project is one where green power or heat is generated for local government or First Nation facilities or where the project is specific to one building or set of related buildings and there are no additional customers or billing. A green energy utility distributes green power or heat to buildings external to the project and/or a formal utility has been established to bill for energy consumed.

In a full ownership model without an operating contract[3], a local government or First Nation chooses to own all of the generation and distribution assets associated with a project or utility. All regulatory and operational control resides with the local government or First Nation and they will both operate and maintain the system.

If a local government or First Nation is considering full ownership of a green energy project or utility, they should be aware that:

- Full ownership for local governments and First Nations carries a high level of accountability to the community.
- Considerable financial resources are required to overcome start-up costs. Staff will need to identify and apply for grants and/or loans, a time consuming process.
- Managing the requirements of multiple funders can be time consuming.
- Learning curves can be steep. Staff expertise will be required for design, planning, construction and operation.
- Processes will need to be managed for hiring trusted consultants and advisors and managing projects.
- Some case study interviewees recommend getting second opinions on feasibility studies and business plans.
- Mechanisms (such as insurance) will be required to protect against risks and liability.

Full ownership makes sense where technology/operational risks are lower, local expertise is available, there are community co-benefits, grants/loans/ reserve funds available and there is some certainty on price for fuel or purchase price for energy. The factors listed below can help mitigate or justify the risks of full ownership:

- strong political support exists
- grants or loans to support start-up are available
- a reliable local and low cost fuel supply is available
- specific equipment to be used is well known and relatively easy to operate
- there is a desire for community and economic co-benefits such as support for a local wood pellet industry, maintenance of community asset that might otherwise be lost, or reduced facility operating costs
- electricity purchase agreements with guaranteed long term price are available
- the project is a pilot supported by grants

[3] For discussion of full ownership with an operating contract, see Section 2(d).

The table below compares full ownership to a joint venture for a range of financial, operational, management and regulatory considerations related to green energy projects and utilities.

Consideration	Full Ownership vs. Joint Venture
Financial	
Access to capital – initial build	**Reduced:** Joint ventures can bring additional resources to the table.
Access to capital – expansion	**Reduced:** Joint ventures can bring additional resources to the table.
Cost of borrowing	**Neutral:** Interest rates available to local government or First Nation unchanged
Non-tax revenue source	**Possible:** If the utility is profitable. Expect that years or decades will be required before capital debt is paid down and the entity is profitable. Note that rate-payers may view excessive rates as indirect taxation.
Access to grants	**Reduced:** Leveraging funds from other sources can improve ability to get grants.
Local government financial risk	**Increased**: Local governments will experience increased financial and development risk; there is a need to consult with experts throughout planning, development and operation.
Can withstand years of losses	**Reduced**: Local government or First Nation may consider selling the asset if losses persist over a number of years. Private partners have larger portfolios and are better able to absorb losses.
Ability to capture offset attributes	**Possible**: Capturing offsets possible under both joint venture (JV) and full ownership but only if the JV contract explicitly assigns environmental benefits to your organization. Also, be sure to read the fine print in grant applications. Most contracts with utilities will assign environmental benefits to the utility. Note that offsets generally are only applicable to heat generation or remote (off-grid) electrification.
Operational	
Technical expertise	**Neutral:** Private partners have broad experience in renewable energy implementation; however a local government may consult with various experts throughout planning, development and operation (although this will increase costs somewhat).
Operational flexibility	**Neutral:** In some cases, greater local government or First Nation control can increase the ability to be responsive to local conditions. In other cases, private sector control can increase access to solutions to operational difficulties.
Admin and monitoring scale	**Reduced:** A joint venture may have benefits over full ownership if the private sector partner is involved in multiple utilities and has established central monitoring, customer care, and back-office (billing, accounting, IT) to support multiple utilities.
LG/FN insulation from risk	**Reduced:** Local governments and First Nations can address lack of knowledge by consulting with experts but overall financial risks (e.g. cost overruns) are higher in full ownership models.
Alignment with public interest	**Increased:** Greater local control of the resource means that more benefits stay local.
Simplicity	
Complexity of structure	**Reduced:** Local control reduces the need for complex agreements.
Overall simplicity for LG/FN	**Neutral:** Full ownership may reduce the need for extensive consultation and agreements, but at the same time a trusted private sector partner can run with a project, reducing the need for local government or First Nation decision making.
Other	
BCUC regulation	**Reduced:** Local governments and First Nations do not need BCUC oversight for fully owned projects and utilities.
Transparency of rate setting	**Neutral:** Local rate setting is transparent; BCUC rate setting is transparent.
Limits political interference	**Neutral:** Political interference may occur throughout planning, development and operation but joint ventures are not insulated from political interference either, particularly in planning stages.
LG/FN political risk	**Increased:** Financial risks in particular are increased.

The main **advantages** of this model are:

- Control over the project, including the ability to expand the system and make technology selections.
- Lower cost and greater flexibility of capital for local governments, which can access low-cost financing from the Municipal Finance Authority.
- Both local governments and First Nations are better placed than private companies to access grant monies from senior levels of government.
- First Nations can have additional tax advantages associated with ownership.
- Flexibility and synergies with other operations. For example, staffing needs may be reduced by integrating staff across the project and other operations.

There are **disadvantages** to full ownership. By directly owning and operating an energy project or utility, a local government or First Nation takes on all the risks, financial and legal, associated with running the project. The local government or First Nation must have, or be able to acquire, significant in-house expertise to commission (and perhaps design and build), operate and manage the system. There may be a need to add a core municipal function, which requires public and political support.

There are also costs associated with acting as an energy utility. Depending on how the system is structured, these are likely to include the purchase and placement of infrastructure, operation and maintenance, administrative costs (including metering and billing), as well as regulatory and governance costs. Cost savings can be achieved if existing utility structures, such as a local hydro supply or history of managing a utility, are in place.

More detailed information on considerations for full ownership can be found in Volume 1 (*Making Investment and Governance Decisions*).

Case Study #6: Solar T'Sou-ke: Leading the Way Back to Sustainability

System Overview		System Governance	
Community: T'Sou-ke First Nation	**Population:** 160	**Venture Partners**	N/A
Owner: T'Sou-ke First Nation	**Operator:** T'Sou-ke First Nation	**Operating Agreements**	N/A
Year Started: 2009	**Connections:** 36 homes; 3 community buildings	**Other Investment Sources**	$1.5 M from 15 governmental, non-profit and private sources (see section 2 below)
Generation Source: Solar thermal and Solar photovoltaic		**Rate Setting/ Project Oversight**	Chief, council and community
Generation Technology: 75 kW solar energy plant includes 3 photovoltaic systems: one system simulates an off grid location to be used with a diesel power system; one system is emergency back-up and net zero operation; and one system 'feeds in' BC Hydro grid. A battery bank stores excess power.		**Billing Method**	Three net metering agreements with BC Hydro
		Legal Structures	First Nations Government
Generation Capacity: 37 thermal panels on individual homes; and 75 kW electricity supplies administration building			
Energy Produced: Heat √ Electricity √			
Distribution System: In-building Solar hot water. Community buildings connected to BC Hydro grid. Billed for total consumption minus their total generation in a given billing cycle.			

System Financing		
Phase	**Cost**	**Funding**
Planning	$25,000	Indian and Northern Affairs (INAC): $25,000
Construction	$1,500,000	$1.5 million from 15 governmental, nonprofit and private sources – covered 90% of solar PV installation costs
Operation	Annual cost: $100 for battery maintenance.	Annual income: PV Electricity BC Hydro Net Metering $20,000. Solar Hot water has led to an annual 10-20% reduction in costs

1. Background

The T'Sou-ke First Nation solar hot water and photovoltaic project was conceived through a community visioning process, where the T'Sou-ke community explored traditional values and sought ways to project those values into the future. Energy security/sustainability and "back to the future" energy systems were identified as top priorities, as was the desire for energy autonomy.

The project was conceived, implemented and managed by the T'Sou-ke Nation to benefit its members and to provide a demonstration project for other First Nations. The sustainability visioning project took one year but, once energy sustainability was identified as a goal, implementation was fast and the project took only three months to construct.

Solar T'Sou-ke includes three solar demonstration projects. One project demonstrates how to achieve off- grid status, the second demonstrates net zero approaches and emergency back-up systems and the third consists of a set of panels providing electricity to the BC Hydro grid.

2. Cost/Benefit

The system is expected to have a 7.3 year return on investment for the off-grid system as compared to a diesel system. Estimated greenhouse gas emission reduction savings are 9 tonnes of GHG emissions annually. After an initial planning contribution amount of $25,000 from Indian and Northern Affairs, $1.5 million was raised from an additional fifteen funding partners. Funding from multiple sources required careful management over the course of the project. The project was funded in 3 parts and partner contributions are summarized in the following table:

Project Component	Funders	
Photovoltaic	Western Economic Diversification Day 4 Energy INAC CCP Home Energy Solutions	EcoEnergy T'Sou-ke INAC FNIF ICE Fund
Solar Hot Water	Natural Resources Canada BC Hydro Power Smart BC Ministry of Environment	SolarBC CSETS Service Canada
Conservation	EcoAction BC Ministry of Energy	BC Hydro

Economic benefits have included developing community expertise in implementing and supporting new technology. The community has demonstrated that renewable technology can create jobs. Social benefits of the project have included building capacity from within the community. Every family had someone involved in the project, which was a great achievement for a small community.

3. Governance

The goals of energy security and community resiliency, identified through the sustainability visioning process, have been achieved: T'Sou-ke First Nation is now selling power back to the grid, the community is not affected by power outages in the neighbouring community of Sooke, and the battery backup system provides an essential service for community emergency readiness.

The community now hosts a flourishing eco-tourism program to share their experience and promote the potential of solar technology. Many tourists and businesses from around the world arrive weekly to learn about the T'Sou-ke experience.

4. Operation

J. Bekker from the University of Victoria completed a technical/financial analysis of the project for the T'Sou-ke Nation. The 75kW photovoltaic project is a demonstration project modeled from an on/off grid photovoltaic New Sulzer diesel power system and a net metering system. For both systems, RETScreen was used to determine expected annual power production, GHG reductions and payback periods. This analysis concluded that:

- The 6.3kW off-grid system is projected to be both viable and cost effective while achieving GHG emissions reductions of 7.7t CO_2e/yr. based upon using photovoltaic power for approximately 50% of the load. Considering diesel costs of fuel at 2$/litre and $.90/kWh, project payback is 7.3 years. Diesel costs savings over the lifetime of the project will be approximately $220,000.
- The battery backup grid tied systems deliver the greatest value by providing emergency power during grid power outages. Emergency power provides communication, kitchen appliances, heating and other emergency loads necessary to maintain health and safety during a grid power outage.

This emergency system is essential for every community and cannot be characterized by financial parameters.

The project has achieved four community goals:

- Part of the community is now off the electricity grid
- A net-zero energy balance has been achieved for several buildings
- Energy is stored on-site for emergency situations
- The community is able to feed energy back into the grid

5. Lessons Learned

- Government subsidies and incentives, such as tax credits and rebates, are essential to economic viability of grid tied systems, especially for home owners.
- Conserve first, innovate second. An improved project approach would involve implementing more cost effective conservation measures (such as changing habits of energy use, improving insulation) first, and then seeking renewable sources of energy to address remaining demand. Adding photovoltaic is easier than changing habits, but is much more expensive. If changes are approached via a planning hierarchy-starting with the cheapest and most effective measures – a community can achieve a 50% reduction without spending a great deal. In BC, First Nations can receive energy saving kits from BC Hydro under the Energy Conservation Assistance Program. These kits include light bulbs, low flow shower heads, and insulation. While these measures are not as exciting as photo voltaic panels, they can be very effective.
- Experience is important. The first contractor lacked experience and eventually went bankrupt. An extra $100,000 has been raised to fix problems.
- One of the best things a community can do is have a conversation with its youth. If you can get the youngest members of the community involved, you will meet your targets.
- Use the opportunity to train members of your community and generate employment.
- J. Bekker's analysis concluded that to promote the use of renewable energy, the feed-in tariff must be set at a premium price. In BC in 2009, any rate greater than $0.30/kWh would be needed make these photovoltaic systems economically competitive. Since then, the price of solar panels has dropped substantially, changing the business case for these kinds of projects.
- The net metering systems are not projected to be viable and profitable systems when used in other applications, in part because it is unrealistic to expect that every project will receive 90% grant funding. Revenue from electricity sold is projected to be $5,400/yr.

6. Sources and Links

- J. Bekker, *Power Production, Emission and Financial Analysis for T'Sou-ke Nation's Photovoltaic Demonstration Project*, October, 2009 (University of Victoria), prepared for T'Sou-ke Nation.
- T'Sou-ke Solar Community Video, December 7, 2009

Interviews with:

- Chief G. Planes, T'Sou-ke First Nation
- A. Moore, Special Projects Manager T'Sou-ke First Nation

Photo credit: A. Moore, Special Projects Manager, T'Sou-ke First Nation

Case Study #7: Kelowna Landfill Gas to Electricity Microturbine Pilot Project

System Overview		System Governance	
Community: Kelowna	**Population:** 122,000	**Venture Partners**	None
Owner: City of Kelowna	**Operator:** City of Kelowna	**Operating Agreements**	Interconnection and purchase agreement with FortisBC
Year Started: 2005	**Connections:** 1 (to FortisBC Electric)	**Other Investment Sources**	Microturbine on lease from CanmetENERGY Technology Centre (NRCan) for $10/yr. for first 3 yrs.
Generation Source: Landfill gas		**Rate Setting/ Project Oversight**	FortisBC agreement at 5 cents/kWh
Generation Technology: 3 Capstone C30 microturbines. (30 kW each)			
Generation Capacity: 90 kW capacity, which generated 221,592 kWh of electricity in 2009.		**Billing Method**	N/A
Energy Produced: Heat X Electricity √		**Legal Structures**	Annual gas and electrical operating permits through Safety Approval Branch.
Distribution System: Microturbines generate power for landfill operations, with excess sold to FortisBC			

System Financing		
Phase	**Cost**	**Funding**
Planning	Minimal in-house	
Construction	$15,000	Microturbine on lease from CanmetENERGY Technology Centre (NRCan) for $10/yr. for first 3 years.
Operation	Annual operating cost $23,000	Annual Revenue $15,000 to $20,000 Project is revenue neutral

1. Background

In 2004, City of Kelowna staff learned about burning landfill gas and using microturbine technology to create electricity. They then consulted with a local expert who was familiar with a microturbine pilot project at the City of Calgary's Shepherd Landfill. He indicated that size, waste conditions and potential for landfill gas generation made Kelowna's Glenmore Landfill an ideal candidate for a microturbine pilot project. Because horizontal landfill gas collection pipes had already been installed as part of the Glenmore Landfill's comprehensive management plan, there was an opportunity to pilot the technology in Kelowna.

A CETC portable trailer-mounted microturbine power system had been installed at the Calgary pilot site in 2002 through funding provided by Environment Canada's Climate Change Program. After endorsement by Kelowna City Council, and a competition with five other organizations, Kelowna won the right to take over the pilot, including the equipment. The City entered into a lease-to-own agreement with Natural Resource Canada's CanmetENERGY Technology Centre for the microturbine trailer, paying $10/year for a period of three years. In 2005, the City of Kelowna won a Union of BC Municipalities Community Excellence Award (for large communities) for this project.

2. Cost/Benefit

Start-up costs for the City were approximately $15,000. The equipment costs around $20,000 per year to operate. Costs are offset by electricity sales to FortisBC. As a technology demonstration centre, the project does not intended to generate revenue but it does offset operation and maintenance costs. In 2008, through methane flaring and burning landfill gas to generate electricity, approximately 5,000 tonnes of CO_2 emissions were reduced and 195,000 kWh of electricity were generated. In 2009, the microturbines and flares consumed about 45,500,000 standard cubic feet of landfill gas combined and generated around 221,592 kWh of electricity. About 430 tonnes of methane emissions were avoided and CO_2e emissions were reduced by 9,010 tonnes.

3. Governance

Glenmore Landfill owns the landfill site and, because of its location, is able to operate the system within existing property lines and within the limits of noise bylaws. The City has acquired the mandatory gas and electrical operating permits from the BC Safety Authority.

4. Operation

Microturbines are connected to a series of horizontal pipes placed underneath the solid waste. These pipes collect landfill gas and direct it through the microturbines, which burn the gas to generate electricity. Excess gas is burned off using a utility flare. When landfill gas is flared, methane is converted into carbon dioxide, reducing greenhouse gas emissions. Electricity generated (the equivalent of that required to power around 70 homes) is sold to FortisBC at five cents per kWh. Between flaring and burning of the gas to generate electricity, virtually all greenhouse gas emissions and other air contaminants are eliminated from the landfill.

Over the initial three year pilot period, landfill gas was carefully monitored for quality and quantity. Only 6% of the available landfill gas was tapped during the pilot project, leaving significant potential to expand the system. In year five, the operation was expanded with two more microturbines and a larger compressor. The project encountered operational issues for the first few years but as of 2011, equipment runs at full capacity. With three microturbines running 70% of the time, revenues could become as high as $30,000/yr.

5. Lessons Learned

- Selling gas provides a better payback than burning it and it is supported by incentives. Electricity may become more viable if part of a combined heat and power system. This is currently not feasible at the Glenmore landfill.
- Cleaning the fuel before burning protects the boilers. Exposure to landfill gas corrodes the high density polyethylene pipes, reducing life expectancy of some of the construction parts to five years.
- Local, technical “oil patch” and millwright expertise is essential. In initial stages of the pilot, there were no local resources available for parts and repairs.
- Meeting the Province’s 2011 landfill regulations means flaring landfill gas at 98% efficiency, which requires an enclosed flare stock that can cost over $2 million. Burning gas reduces greenhouse gases by 21%, so the regulations also incentivize using gas for energy instead of flaring it.
- Managing landfill gas in a larger landfill is mandatory. This project has shown that microturbines are a good option for electricity generation at smaller landfills.

6. Sources and Links

- Civic Info BC: Projects and Innovations database (City of Kelowna)

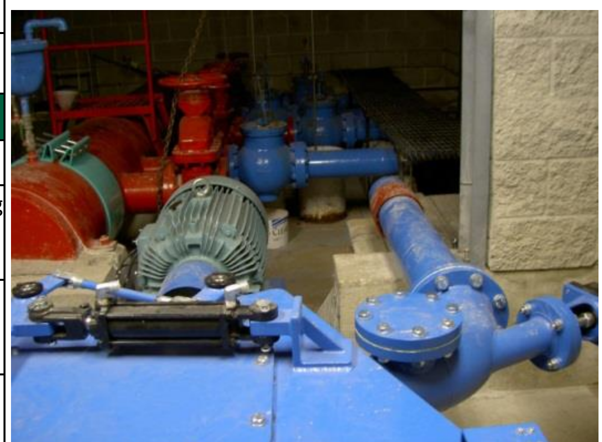
Interview with: Darren Enevoldson, Landfill Gas Specialist, City of Kelowna.

Photo credit: D. Enevoldson, City of Kelowna

Case Study #8: Kimberley Micro Hydro in Water Supply Project

System Overview	
Community: Kimberley	**Population:** 6,600
Owner: City of Kimberley	**Operator:** City of Kimberley
Year Started: 2010	**Connections:** 1 building + BC Hydro grid
Generation Source: Hydroelectric power	
Generation Technology: Reaction and impulse turbines	
Generation Capacity: 12 kW (rated for 25kW with peak output of 28kW)	
Energy Produced: Heat X Electricity √	
Distribution System: BC Hydro net metering for microturbines	

System Governance	
Venture Partners	No
Operating Agreements	No
Other Investment Sources	N/A
Rate Setting/Project Oversight	N/A
Billing Method	N/A
Legal Structures	N/A



System Financing		
Phase	**Cost**	**Funding**
Planning		Green Municipal Fund planning grant (2007) supported a feasibility study
Construction	$1,185,000	Green Municipal Fund grant provided $189,000 for turbine purchase and installation
Operation	Minimal maintenance for turbine	Revenue $17,082/year; Net surplus value of $3,680/yr. in reduced energy costs.

1. Background

In 1997, Kimberley constructed the Mark Creek Dam, creating a reservoir that holds 60 million litres of water. Although the original intent of the project was to ensure the City's water supply, the City took advantage of local microturbine expertise to explore opportunities to generate power, in part because BC Hydro had just begun accepting net metering applications for electricity. Study results indicated that adding a microturbine to the system was a relatively simple enhancement. Between 1997 and 2010, the City applied for grants to support the project.

Although a significant amount of time was required to build the project, the system is now generating enough power to operate the City's water chlorination plant.

2. Cost/Benefit

The feasibility study was based upon results of a RETScreen energy model (developed by Ministry of Natural Resources). Using input from projected head and flow duration curve data, the maximum flow that can be used by the turbine is determined. Capital, operations and maintenance costs are estimated, and years to positive cash flow projected. Both planning and capital costs for the project were funded by Federation of Canadian Municipalities' Green Municipal Fund, in 2006 and 2007 respectively. Construction began in 2008.

Simple return on investment is estimated at 11 years based upon cost of purchasing/installing the turbine, taking into account annual revenue and energy cost savings. As the system powers the chlorination plant, the reduced energy use is estimated at a value of $13,000/yr.

3. Governance

The City's decision to proceed with the project was the result of several factors:

- The City was already committed to upgrading its water supply.
- Funding support was readily available from the Green Municipal Fund.
- BC Hydro had created the opportunity to supply power to the grid via its net metering program.
- A local microturbine technician was available to develop an easy-to-install prototype, which is now used worldwide.

4. Operation

Water from the Mark Creek water supply pipe flows through a Turgo turbine. Two nozzles control the rate of flow through the turbine so that it matches City water demand, then water is discharged into the head tank below the turbine. The turbine generates power, which is supplied to BC Hydro's grid through the net metering program. Available water is 9,000 to 18,000m^3/day, enough to generate 12 kW and power the chlorination plant. The microturbine features 35 m head (50 psi) nominal capacity 25 kW (firm capacity 15-17kW) and power use at site 11kW - 15kW. Maximum flow is 102 l/s and firm flow (90%) = 60 l/s. The microturbine has its own programmable logic control, which means it can operate unattended.

Experience has shown that maintenance of the turbine is minimal and maintenance costs do not require a separate line in the budget. Overall revenues of $17,080 per year are calculated based upon the 170,820 kWh generated per year, valued at $0.10/kWh. Once the value of electricity supplied to the chlorination plant is taken into account, the project is generating a surplus of $3,680 per year.

BC Hydro's net metering program requires microturbines less than 50kW to offset customer's electrical power requirements while satisfying BC Hydro's connection requirements. When there is a power outage, the system must be shut down for safety reasons.

5. Lessons Learned

- The project was worthwhile, although it was a lot of work for a relatively small benefit. Larger scale applications would reap greater benefits.
- The kind of turbine used (an impulse turbine) is very suitable for micro hydro applications: It has a greater tolerance of sand and other particles, there is better access to working parts, pressure seals around the shaft are not required, it is easier to fabricate and it generates better part flow efficiency. The system is self-sufficient, requiring little maintenance after installation, although this kind of turbine is not suitable for water supply systems with low heads.
- The system could be easily replicated by other communities, as long as the water supply is available. Combining water supply systems with power generation makes double use of the resource.

6. Sources and Links

Interviews with:

- Mike Fox, Manager Operations & Environment Services, City of Kimberley
- Troy Pollock, Manager Planning Services, City of Kimberley
- Don Schacher, Project Coordinator, City of Kimberley

Photo credit: *City of Kimberley Uses Micro Turbine to Generate Power From its Water System* (by Opus DaytonKnight & City of Kimberley), BC Water & Waste Association

Case Study #9: Burns Lake Arena Biomass Project

System Overview	
Community: Burns Lake	**Population:** 3,614
Owner: Village of Burns Lake	**Operator:** Village of Burns Lake
Year Started: 2011	**Connections:** 1 building (Tom Forsyth Memorial Arena)
Generation Source: Wood pellets	
Generation Technology: Three Froling P4 60 kW (200,000 BTU/hr.) pellet boilers	
Generation Capacity: 180kW (600,000 BTU/hr.)	
Energy Produced: Heat √ Electricity x	
Distribution System: Glycol treated water, closed loop design with three heat sources: waste heat recovery from ice plant, pellet boilers and a natural gas boiler for heating.	

System Governance	
Venture Partners	No
Operating Agreements	N/A
Other Investment Sources	None
Rate Setting/Project Oversight	N/A
Billing Method	N/A
Legal Structures	N/A

System Financing

Phase	Cost	Funding
Planning	$18,000	
Construction	$419,000	Community Works Fund: $222,880; Towns for Tomorrow Grant: $196,000; Municipal Gas Tax Fund: $18,000
Operation	$21,010/yr. for pellets, expected	Anticipated savings of $8,000/yr. from an 80% reduction in natural gas consumption

1. Background

The Village of Burns Lake is one of many BC communities significantly impacted by the Mountain Pine Beetle epidemic. When two wood pellet mills opened nearby, Council saw an opportunity to heat the village arena with locally sourced pellets, allowing the municipality to support the growing local pellet industry while stimulating local growth and economic recovery.

In 2011, Burns Lake worked with Green Heat Initiative (GHI) to identify the scope and scale for a biomass heating system for the municipally owned and operated Tom Forsyth Memorial Area (TFMA). GHI completed a pre-feasibility analysis for the project, which was used to clarify the opportunity, help secure funding, respond to questions and provide linkages to information sources. For the Village of Burns Lake, the arena is the first of what Village Council hopes to be many municipal buildings heated by a renewable energy source.

Installation and testing of the new biomass heating system began in July, 2011. The system replaces some of the natural gas and electricity previously used to heat the arena. The arena project will use pellets to heat water for ice resurfacing and domestic use as well as heating change rooms and part of the viewing area. Depending on the outcome of this installation, the heating system may be expanded to include the remaining bleachers and the adjacent curling rink.

The intent of the project was to lower operating costs, reduce greenhouse gas emissions, replace aging infrastructure and help support local industry. The Village of Burns Lake received an Honourable Mention at the 2011 Climate & Energy Action Award for the project.

2. Cost/Benefit

The village received a $196,000 provincial Towns for Tomorrow grant and has also used $18,000 from the Municipal Gas Tax Funds to help fund the project.

A report from Canadian Biomass Energy Research Ltd. provided information on the feasibility and costs. Excluding grants, a simple payback of 9-22 years was calculated, with the broad range due to unknown savings from the new heat recovery system. If replacement capital costs are assigned to asset maintenance and upkeep, payback is 3-7 years. The system is expected to reduce natural gas consumption by about 70-80% and achieve energy savings of approximately $8,000/year as well as contributing $8,000/year to the local economy from purchase of pellets. Estimated savings in heating costs are expected to be significant; most likely somewhere between $4,200 and $12,650 annually. Greenhouse gas emission reductions are estimated at 40 tonnes of CO_2 per year.

3. Governance

The system is owned and operated by the Village of Burns Lake, and the heat is used by the municipal arena.

4. Operation

Residential white wood pellet consumption is estimated to be around 110 tonnes at a cost of $191/tonne delivered. Prices have more than doubled since the first load. The local building supply store sources pellets and delivers via truck mounted crane with assistance from the arena staff, who have received training on how to use the new system. Pellet storage and the boilers are located just outside the arena, immediately adjacent to the ice plant.

5. Lessons Learned

- Burns Lake was able to reduce corporate GHG emissions and reduce energy costs in the arena.
- The project was more complicated that originally envisioned. Having a good working relationship with the engineering and installation team is essential.
- Seek guidance from the BC Safety Authority on acceptable boilers during the preliminary design process and include a list of "preferred" boilers in the contract tender. It is important to understand that not all pellets are created equal; consider obtaining a small sample of the pellets to send to the boiler manufacturer for testing prior to the contract tender.
- Pellet supply and delivery has proven challenging. Local pellets were not compatible with the system due to high dust levels. The Village continues to work on sourcing local supply and fine tuning the boilers.
- Modern wood heating is clean, efficient, convenient and cost effective. Emissions from the Froling boilers are expected to be well below even the strictest environmental standards. The boilers are very safe and meet and exceed all safety requirements by the BC Safety Authority. No special permits were required.

6. Sources and Links

Green Heat Initiative

Interview with: Jeff Ragsdale, Development Services Coordinator, Village of Burns Lake.

Photo credit: Wood Waste 2 Rural Heat

Case Study #10: Gibsons District Energy System

System Overview	
Community: Gibsons	**Population:** 4,400
Owner: Town of Gibsons	**Operator:** Town of Gibsons
Year Started: 2010	**Connections:** Phase 1A: 35 residential units
Generation Source: Geoexchange	
Generation Technology: Geo-Xergy Systems ground heat exchanger (GHX) and residential heat pumps	
Generation Capacity: Phase 1 field and distribution pipes sized for 35 residential units; pump house sized for 116 lots	
Energy Produced: Heat √ Electricity x	
Distribution System: 3 horizontal "slinky" fields of coils, each with 5,700 m of circuit pipe. Distribution pipes carry a water-ethanol solution and connect to a pump house and each home.	

System Governance	
Venture Partners	No
Operating Agreements	No
Other Investment Sources	No
Rate Setting/Project Oversight	Rate set by Council at 15% less than cost of natural gas. Each customer pays individualized rate based on home heat loss calculation.
Billing Method	Customers billed semi-annually by Town; $150 connection fee
Legal Structures	Gibson's District Energy Utility Bylaw 1128 sets rates and establishes areas that must connect

System Financing

Phase	Cost	Funding
Planning		$20,000 (2008 Community Action on Energy & Emissions grant); $10,000 (2008 BC Local Government Planning Grant)
Construction	Total project: $1,400,000	$244,080 - Island Coastal Economic Trust; $325,115 - Innovative Clean Energy Fund; $256k - Gas Tax; $190k – Town; estimated $385k from developer for distribution system
Operation	Undetermined (maintenance is low)	Projected Annual revenue: ~$39,000/yr. (Phase 1A); 60% energy savings

1. Background

In 2008, the Town of Gibsons completed a study showing good technical and economic potential for a geoexchange district heating system in Upper Gibsons. The Town was committed to developing this area sustainably, its CAO had previous experience with district energy, and a local land owner and developer was willing to contribute to the system. In 2008, the Town acquired funding for the system and development of Phase 1 broke ground in 2009.

The project will be developed in phases according to development demand and is intended to operate on a stand-alone basis for each phase, negating the need for large investments in infrastructure upfront for future phases. Phase 1A of the system was competed in 2010 and it is now connected to 27 lots that will eventually contain 35 residential units. In total, Phase I will include about 116 residential lots.

The system will service all new residential and commercial buildings in the vicinity as well as some existing buildings, including the ice arena and curling rink. The Town of Gibsons won the 2009 Climate & Energy Action Award in the Community Planning and Development category for the Upper Gibsons Neighbourhood Plan.

2. Cost/Benefit

Simple payback for homeowners (compared to natural gas) is 8.1 years. Homeowners benefit from reduced heating and carbon tax costs, long-term price stability and reduced environmental footprint. Payback for the Town should be of the order of 10.4 years. The Town benefits from the potential of an additional long-term, and non-taxation revenue source, plus local economic development in the order of $4,200 per year per household connected (based on annual energy expenditure for the average BC household).

GHG emission reductions are estimated at 335 tonnes/year when Phase I residential construction is complete, and 1,768 tonnes/year at full build-out.

3. Governance

The system is run by the Town and operated as a utility. The Town installed and owns the geoexchange field, pump house and distribution pipes up to the property line. The homeowner owns all pipes and equipment installed within private property boundaries. A district energy (service area) utility bylaw (Town of Gibsons District Energy Utility Bylaw No. 1128) set the rates and established which areas must connect. Rates are designed to undercut natural gas rates by 15%. Individual charges (and size of the heat pump) are based on a heat loss calculation for each dwelling that is required when applying for a building permit, so more energy efficient homes have lower bills. Consumption is not metered. Homeowners pay two fixed charges which total about $500 per year for a 140m^2 home, or $3.57/m^2. The heat pump cost is about 30% more than a conventional heating and cooling system but savings on heating and cooling offset that price.

4. Operation

The system is built upon a horizontal geoexchange loop located in a park. Water/ethanol fluid is pumped through the system distributing heat from the ground to individual buildings which have installed a heat pump to extract heat (and cooling in the summer) from the system.

5. Lessons Learned

- The possibility of supplementing tax revenues with utility revenues was appealing to Council.
- Individual charges based on calculated heat loss encourage the construction of energy efficient homes.
- When system economics is dependent on the housing development market, downswings in the economy have a significant impact.
- There are cheaper alternatives to high-density polyethylene pipes which would work just as well. Local suppliers can offer deals on equipment.
- Expertise in geoexchange systems helps achieve cost savings.
- When project construction is based on grants, timelines are critical.

6. Sources and Links

- Partners for Climate Protection, FCM GHG Initiative of the Month January 2012
- *The Regulation of District Energy Systems*, Peter Ostergaard. Smart Planning for Communities. May 2012.

Interview with: David Newman, Director of Engineering at Town of Gibsons, & Michael Epp, Municipal Planner at Geo-Xergy Systems Inc.

Photo Credit: Island Coastal Economic Trust

Case Study #11: Revelstoke Community Energy Corporation Utility

System Overview	
Community: Revelstoke	**Population:** 7,300
Owner: Revelstoke Community Energy Corporation (RCEC)	**Operator:** RCEC
Year Started: 2005	**Connections:** 10 buildings
Generation Source: Biomass (sawdust) from the Downie sawmill	
Generation Technology: 1.5 MW biomass boiler with 1.75 MW backup propane boiler	
Generation Capacity: 3.25MW	
Energy Produced: Heat √ Electricity X	
Distribution System: Steam for Downie's dry kilns and hot water for district energy system are distributed through 2.3 km of insulated piping	

System Governance	
Venture Partners	No
Operating Agreements	Operating Service Agreement with Downie Timber for shared cost of an operator 20 year biomass fuel supply agreement with Downie Agreement to supply steam for sawmill dry kilns 20 year energy supply agreements with each customer
Other Investment Sources	Loan from Revelstoke Community Forestry Corporation, $1.25M
Rate Setting/Project Oversight	Rates are based on individual customer's avoided cost, with a goal of setting rates at 5% less than those avoided costs (i.e., estimated energy costs and maintenance and amortization of boiler over 20 years)
Billing Method	Billed according to metered energy use
Legal Structures	City of Revelstoke established wholly owned subsidiary for energy corporation

System Financing

Phase	Cost	Funding
Planning	$10,000 (heat only feasibility study)	Federation of Canadian Municipalities (FCM) grant, 2003
Construction	$6,990,000	Towns for Tomorrow: $380,000; FCM GMF grant: $1.8M; Revelstoke Credit Union: $1M; FCM GMF Loan at ~3.5%: $1.35M; City Preferred Share Purchase: $1.2M
Operation	2011 operating cost: $577,000 (amortization of $153,500 included) 2012 operating cost: $620,000 (amortization of $157,600 included)	Annual revenue: $641,000/yr. Cost Savings: Energy rates are indexed to the cost of living and customers are relieved from volatility of propane prices.

1. Background

Air quality was a serious concern for the citizens of Revelstoke, in part because of emissions from the annual incineration of about 70,000 tonnes of wood residue in a beehive burner at the Downie Mill. Various studies and plans completed throughout the 1990s suggested that a district heating system could be a solution to both Downie's wood residue disposal costs and the community's reliance on propane as a heating source.

The City initially considered a combined heat and power solution which proved not to be economically feasible. The City decided to pursue a heat only project, and development of the Revelstoke Community Energy Corporation (RCEC) district energy system began in late 2003 with operation starting in June

2005. The first six buildings were connected over the next two years and in 2009-2010 four buildings were added. The City is now considering expanding the plant and adding co-generation capacity.

In 2004, RCEC received the Energy Aware Award from the Community Energy Association. In 2005, it received a Sustainable Communities Award from the Federation of Canadian Municipalities. RCEC is considered a valuable community asset.

2. Cost/Benefit

Funds of nearly $7 million were required to design/build the plant and initial distribution pipes: $3M for the central plant and equipment; $2M for various construction phases; $1.1M to install energy transfer stations and $0.9M for construction financing, developer's costs, etc. This was all funded and financed by a combination of grants, debt, and equity, as shown in the table above.

The system displaces 3,400-3,700 tonnes/year of greenhouse gas emissions while providing a non-taxable, non-tax source of City revenue, improving local air quality, and saving customers money on their heating.

Simple payback for the project is 13 years, return on investment is 5.3%, and return on equity is 8.8%.

3. Governance

RCEC is a wholly owned subsidiary of the City of Revelstoke. The City appoints a Board of Directors to run the corporation, which includes three Councillors, one staff member and three appointed community members. The plant is located at the Downie mill and RCEC and the City jointly fund an experienced Downie employee to operate the energy plant part-time. RCEC has a secure 20 year biomass fuel supply agreement with Downie Timber and an agreement to supply steam for the sawmill dry kilns.

Contracts are for 20 years and are linked to inflation. The price of energy specified in newer contracts will be 85% dependent on BC's consumer price index and 15% on the energy price index.

4. Operation

Boilers heat the heating medium (oil) which is passed through a steam generator for delivery of steam to Downie's dry kiln, and passed through heat exchangers generating hot water that is distributed into 2.3 km of insulated district energy pipes. 50% of the heat generated is used as steam for Downie's dry kilns and 50% for heating and domestic hot water for major buildings in the city. Each building connected to the system has a heat exchanger that extracts the heat from the hot water and transfers this heat to the building heating systems, which usually includes space heating and domestic hot water. Each building also has a meter to monitor use for billing. The propane boiler provides backup and peaking capacity for the coldest times of the year. The project aims to use 85% of heat from biomass and 15% from propane annually.

There is a cyclone and electrostatic precipitator on the system to ensure clean effluent gases. The fuel bin holds a 2-3 day supply of fuel.

5. Lessons Learned

- Ensure that the original projections have lots of contingency built in and that all project timelines are reasonable.
- Having all customers connected to the system from the beginning would have been beneficial.
- There was a learning curve on boiler operation including fuel feed modifications (from hog fuel to sawdust) and adjustments for variations in the sawdust over the year.

- Unforeseen operational issues included:
  - original heat exchangers failed and had to be replaced;
  - water for heating was contaminated with thermal oil, originating from leaking tubes in the steam generator;
  - steam generator and combustor pipe corrosion occurred despite following prescribed water procedures;
  - replacement of an inferior quality refractory was required in year four; and
  - there was a fire in the hydraulics room in December 2009, justifying the existence of the propane backup boiler.
- Qualified backup staffing is a problem in small communities.
- Small plants lack economies of scale.
- Forming energy supply agreements is challenging because seasonal boiler efficiency is difficult to explain and energy pricing for customers is based on "avoided costs," which can lead to disagreements. Energy supply contracts with customers must provide means to recover unexpected costs. This led to the modification of the price adjustment clause in our newest energy supply agreements.
- Knowledge about district energy lacking in key Federal and Provincial government departments, but is growing due to legislative requirements now in place in BC.
- It is important to have a committed Council with a will to complete the project over an extended period of time and a Community Energy and Emissions Plan to give future direction.
- Other important items were: broad support from an informed, confident community; a project champion; hiring of proven, effective staff and consultants; luck and timing.

6. Sources and Links

- *Biomass-The Revelstoke District Energy Experience* (G. Battersby Director RCEC Oct 23 presentation at 2010 Columbia Basin Symposium)
- City of Revelstoke District Energy Expansion Pre-feasibility Study Final Report, January 2011
- Community Energy Association Clean Energy for a Green Economy
- *Lessons Learned from the Revelstoke District Energy Experience* (Oct 20, 2011 presentation)

Interviews with:

- Geoffrey Battersby, President, Revelstoke Community Energy Corporation,
- David Johnson, Past President, Revelstoke Community Energy Corporation

Photo credit: Revelstoke Community Energy Corporation

Case Study #12: Ty-Histanis District Energy Geo-exchange

System Overview		System Governance	
Community: Tla-o-qui-aht First Nation, Central Vancouver Island	**Population:** 345	**Venture Partners**	No
Owner: Tla-o-qui-aht First Nation	**Operator:** Tla-o-qui-aht First Nation	**Operating Agreements**	No
Year Started: 2011		**Other Investment Sources**	None
Connections: Phase 1 construction: 10 homes & 1 community building; Phase 1 service: 68 lots and community infrastructure; Future expansion: 215 homes.		**Rate Setting/Project Oversight**	Tla-o-qui-aht First Nations
Generation Source: Geoexchange		**Billing Method**	Tla-o-qui-aht First Nations Utility Department collects user fees.
Generation Technology: Geoexchange			
Generation Capacity: Designed to meet the requirements full build-out of Phase 1 of the community (62 lots, health clinic, community buildings and infrastructure)		**Legal Structures**	Tla-o-qui-aht First Nations Housing Policy and Procedures Manual, March 2009
Energy Produced: Heat √ Electricity X			
Distribution System: Centrally located geoexchange field – up to 314 boreholes drilled to average depth of 48 m with headers and pipe collection system to transfer ground heat to central energy plant. District energy pipes distribute ambient temperature water to the buildings, and water heat pumps extract heat/cooling for space heating/cooling and pre-heating domestic hot water.			

System Financing

Phase	Cost	Funding
Planning		Feasibility study (2007), business case (2009) and design brief (2010) funded by AANDC
Construction	Total capital cost = $3,589,889	AANDC: $2,089,889 Innovative Clean Energy Fund: $750,000 TFN User fees: $750,000
Operation	Hydro costs = $3,000 per month	Revenue neutral 50% in energy cost savings (Estimated at $3.5 M at Phase 1 build-out.)

1. Background

Ty-Histanis is a new, sustainable community development and expansion of the Esowista Reserve on Tla-o-qui-aht First Nation (TFN) lands. In 2003, TFN successfully negotiated a Memorandum of Understanding (MOU) between the First Nation, Indian and Northern Affairs Canada (now Aboriginal Affairs and Northern Development Canada or AANDC) and Parks Canada, which removed approximately 86 hectares of land from the Pacific Rim National Park Reserve to address issues of overcrowding on the Esowista Reserve.

The Ty-Histanis development will occur over three phases as houses and community buildings are constructed and occupied. Phase 1, which was completed in 2011, provides geoexchange space heating and cooling as well as domestic hot water to seven houses and three triplexes for elders.

In total, Phase 1 will service sixty-eight lots and one community facility. The project will be expanded to accommodate about 215 housing units and several community buildings.

This culturally significant system will allow for the use of local renewable energy resources and reduce electrical demand for the remote First Nations community. The geoexchange system will displace the use of electricity and propane for heating and reduce greenhouse gases. Because this is a new community, development of the heating system, energy efficient new homes and community buildings will be integrated, leading to efficiencies and the achievement of net-zero energy goals. Through Canada Mortgage and Housing Corporation's (CMHC) "Equilibrium for Communities" funding, Tla-o-qui-aht engaged in an integrated design process to incorporate these goals into the built environment at Ty-Histanis. This utility is the only First Nation district energy system in Canada to be considered net zero, in part because the electricity provided to operate the geoexchange district heat system is generated by hydroelectric facilities.

2. Cost/Benefit

At full build-out of Phase 1, operating expenses will be covered by a user fee of $860 per year (or $72/month). Total energy costs, including electricity charges are about $102/month, about 30% less than typical costs in the region. Expected energy and GHG emission reductions are outlined in the table below:

	Electricity Reduced	Electricity Costs Avoided	GHG Emissions Reduced
Phase 1 (first 25 years)	Annually: 905 MWh Over 25 yrs.: 22.6 GWh	$3.5 M, possibly as high as $5.2 M if BC Hydro tariffs increase	~478 tonnes CO_2e
Phases 1-3 (25 years +)	Over 43.3 GWh	$7.8 M, possibly as high as $11.9 M if BC Hydro tariffs increase	Over 950 tonnes CO_2e

The capital cost of this project was $3,589,889. Aboriginal Affairs and Northern Development Canada provided $2,089,889 for district geoexchange system infrastructure. The Province provided $750,000 toward the construction phase of this project via the Innovative Clean Energy Fund. Tla-o-qui-aht First Nation committed to providing the remaining funding, proposing that the remaining $750,000 of the capital cost be funded by monthly levies on homeowners. The cost of this levy would be covered by the savings realized by the homeowners. Return on investment is estimated at $3.5 million in electrical savings over 25 years, based upon BC Hydro's current rate of tariff escalation. This could be as high as $5.2 million if BC Hydro's tariffs escalate at a slightly higher rate in the future.

3. Governance

The Ty-Histanis Neighbourhood Development project was one of six projects included under Natural Resources Canada and CMHC's EQuilibrium project. Community consultation from 2000 to 2003 established sustainability principles for the new community. In July, 2006 the Tla-o-qui-aht Community Development Advisory Group (TCDAG) was formed. A key task of TCDAG was the completion of a Comprehensive Housing Development Strategy as a means of reflecting and implementing the sustainability principles identified earlier on. Through 2006 and 2007, a number of TCDAG workshops confirmed that housing at Ty-Hystanis should be sustainable and that a geoexchange system was an essential component of the future community.

A district energy system feasibility study, completed in November 2007, concluded that a geoexchange district energy system would provide significant environmental and financial benefits over the typical approach of electric baseboard heating and that a district-wide approach would have lower maintenance costs than installing individual geoexchange systems in each home. A housing policy was developed that established requirements to build energy efficient homes and connect to the district energy system. The policy also provides for user fees to support the system. A community utility department will be created to collect utility charges. The geoexchange district energy system will reduce utility costs for residents, helping to make housing more affordable.

4. Operation

Ground source heat pumps can transfer 3 to 4 kW of energy per 1 kW of electrical energy consumed. Initial energy savings for Phase 1 are estimated at 50% but could increase to 55% to 60% savings as the system efficiencies are realized when all phases are complete.

Benefits of the system include improved energy security, a culturally significant renewable and clean source of energy, improved air quality by reducing the need to burn other fuels, lower energy costs to homeowners, reduced GHG emissions and enhanced affordability for homeowners. The system will also be community owned and maintained, relieving homeowners of the need to operate and maintain complex mechanical systems.

5. Lessons Learned

- The utility provides a unique community-scale opportunity to monitor, assess and report upon the long term operational and economic aspects of a geoexchange district energy system.
- The experience can be replicated by both First Nations and non-First Nations communities.
- Operational components may be more challenging than construction, in terms of how operation and maintenance should be conducted and financed and how to manage cost recovery through user fees.
- Residents of the homes connected to the system report significant cost savings and ease of use.

6. Sources and Links

- Canada Mortgage and Housing Corporation (CMHC)
- *Tla-o-qui-aht First Nations Housing Policy and Procedures Manual*, March 2009
- *Tla-o-qui-aht First Nations Esowista New Community District Geoexchange Energy System*, May 2009
- *Ty-histanis development nearing end of phase one*, Westerly News

Interviews with:
Barb Audet, Housing Coordinator, Tla-o-qui-aht First Nation,
Kathryn Nairne, MCIP, Ron Yaworsky (Partner) and Eliza Waddell, David Nairne + Associates Ltd.
Photo credits: Canada Mortgage and Housing Corporation

Choosing Full Ownership – with Contracted Operation

An energy project may also be structured by vesting total ownership of the system and its assets in the local government and contracting out the servicing and operation of the system to a third party. Choosing full ownership with private operation mitigates some of the risks associated with full ownership discussed in the previous section and Volume 1 (*Making Investment and Governance Decisions*).

Advantages of private operation:

- Council maintains some control, for example through setting rates via bylaws and operating policies, but less so than in the previously discussed models because Council is constrained by contracts signed with the service provider.
- There is potential to benefit from private sector expertise in delivering energy services.
- This approach avoids the extra steps required to receive BC Utilities Commission approval.
- Relatively cheap capital, as above.

In the case of First Nations, if a nation building approach has been taken to the project, ensuring that the "private" operator is a member of the Nation means that the community will reap employment benefits from the project.

Case Study #13: Lonsdale Energy Corporation Utility

System Overview		System Governance	
Community: North Vancouver City	**Population:** 51,000	**Venture Partners**	No
Owner: Lonsdale Energy Corp. (a wholly owned corporation of the City of North Vancouver)	**Operator:** Lonsdale Energy Corp.	**Operating Agreements**	Various agreements
Year Started: 2003	**Connections:** 31 delivery points	**Other Investment Sources**	Governmental grants and loans Developer connection fees Funding agreement with private operator Tariffs and charges to customers Green Municipal Fund ($4 million)
Generation Source: Natural gas, solar and geoexchange			
Generation Technology: Various: Low temperature community energy system, Viessmann condensing natural gas fired high efficiency boilers, Viessmann solar hot water system and Trane heat pumps.		**Rate Setting/Project Oversight**	Lonsdale Energy Corp. via City Council approval of rates.
Generation Capacity: 13 MW		**Billing Method**	Monthly: includes capacity, meter and commodity charges.
Energy Produced: Heat √ Electricity X		**Legal Structures**	Service Area Bylaw (via Section 8(2) of Community Charter Community Energy Agreements (s. 219 Land Title Act covenant)
Distribution System: Hydronic based system. In ground distribution network connects buildings in 4 separate energy grids. System efficiency 82.9%			

System Financing		
Phase	**Cost**	**Funding**
Planning		Feasibility study funded by City of North Vancouver with support from Terasen and BC Hydro.
Construction	$11.,8M (as of 2011)	$2M loan from the City of North Vancouver (similar to a return on bond investments); $2M investment from Terasen Utility Services Inc. (now Corix Utilities Inc.); $2M grant $2M loan from FCM's Green Municipal Investment Fund
Operation	Proprietary	$150,905 profit (2011)

1. Background

When considering plans for the waterfront and adjacent areas in the late 1990s, North Vancouver City Council determined that planning for energy should be an integral part of the planning process. City Council began by taking an opportunity, offered by the Federation of Canadian Municipalities, to tour European district energy facilities. In 1998, the City completed a feasibility study for district heating in three strategic locations. The study recommended a decentralized system using interconnected mini-plants and, as a result, the City pursued a natural gas fueled district heating system in the redevelopment area.

In 2003, the Lonsdale Energy Corp. (LEC) was established to provide district heat, domestic hot water and, eventually, district energy cooling systems for the City. Terasen Utility Services Inc. (which became Corix Utilities Inc.) designed and installed boilers, controls and heat exchangers in the initial energy grid of the district energy system. Corix is still involved in equipment installation, maintenance and billing of that particular energy grid.

The LEC now serves more than 2.4 million square feet of property including 2,131 residential units, a 106 room hotel, numerous offices and commercial outlets and several municipal buildings including City Hall, library, fire hall and community centre and has added solar and geoexchange sources to the system.

2. Cost/Benefit

The feasibility study was jointly funded by the City, Corix and BC Hydro. Funds for construction and implementation came from government grants and loans, developer contributions and connection fees, a funding agreement with a private operator and utility charges to customers. In September 2007, the City was awarded two grants to support the installation of 120 solar hot water panels on the top of the new municipal library. This project creates an alternative energy source for the LEC and reduces the community's reliance on fossil fuels.

On a 20-year financial cycle, LEC provides roughly 4.5% rate of return on investment, however various system components are assessed separately. GHG emission reductions in 2011 were 735 tonnes.

3. Governance

Under Section 8(2) of BC's Community Charter, a municipality may provide any service that Council considers necessary or desirable, and may do this directly or through another public authority or another person or organization. In addition, the municipality may, by bylaw, regulate, prohibit, and impose requirements in relation to municipal services. These provisions provide authority to establish particular types of energy services (e.g. a hydronic district heating system) and to require buildings to connect to the energy service.

The City of North Vancouver established a hydronic heat energy service bylaw to establish a district heating service area for Lower Lonsdale, with a requirement that all new or retrofitted buildings over a certain size (1,000 m^2) use the system, unless it is determined by the City's Director of Finance that cost to the City would be excessive. This bylaw was amended in 2010 to consolidate three distinct service areas and expand the service area to the whole City. This bylaw allows LEC to provide cooling services in buildings planning to be equipped with air conditioning systems. A Section 219 (Land Title Act) Covenant and Statutory Right of Way is used to ensure buildings built on city-owned land or land that has been rezoned are built with hydronic systems and to specific standards in advance of connection (also known as a "Community Energy Agreement"). The City has adopted an implementation strategy, which facilities district heating system growth over time. Developments located remotely from a service area are encouraged to build their projects ready for connection to a future district heating system.

LEC is not regulated by the BCUC because it is a municipally-owned utility. Instead, Council receives regular reports from LEC and approves utility tariffs. LEC customer rates have been amongst the lowest in the Lower Mainland. LEC's regulator, the City of North Vancouver, authorizes LEC management to adjustment the commodity charge to reflect the purchase price of 1,000 GJ/month of gas under Terasen Gas Rate Schedule 3.

4. Operation

LEC uses condensing natural gas boilers to generate heat. It also operates 120 solar panels on the roof of the city library and a recently completed geoexchange system. LEC continues to diversify its energy sources and aims to decrease its reliance on natural gas. It is currently reviewing the possibility of implementing ocean-source technology at the ship yard precinct and bio-energy options.

All new buildings in the redevelopment precinct require underground parking garages. A 'mini-plant', housing from four to six high efficiency condensing boilers, requires a floor area equivalent to several parking spaces. Developers are asked to provide, in certain select building sites, space for a small energy plant. Given that a developer is already required to build a concrete underground parking garage, this requirement has not been a barrier in proceeding with a building project.

The interconnected mini-plant concept provides greater financial and operational flexibility for LEC during system build-out. Marginal costs of system growth are more closely matched with marginal revenues. System changes or improvements can be easily incorporated into future growth with the distributed plant versus a central plant generation model. This approach provides significant flexibility to include new technologies when they become available.

5. Lessons Learned

- During initial stages of system development both LEC and developers faced a learning curve in terms of designing in-building systems, estimating heating demand and correctly sizing the system. Detailed design guidelines have now been developed.
- A district energy system should be planned to provide flexibility for the use of new technologies and most appropriate energy sources when they become available. As alternative fuel sources are implemented and demand grows, gas boilers can transition to peaking boilers.
- The LEC district energy system is scalable, which is an effective way to plan for expansion.
- LEC demonstrates that district energy infrastructure can easily blend with urban form.
- The public sector is well positioned to regulate, control land use, ensure users' adoption and obtain funding for a district energy system. Cross-department co-operation, especially between planning and engineering is important. Close and early co-operation with developers' design teams is also essential.
- High density development (buildings close together) leads to reduced capital investment.
- Development of mini-plants with a local distribution grid enabled the City to manage exposure to financial risk by reducing the scale of initial investment. The mini-plant concept developed by the City was instrumental in getting the project off the ground. By phasing in the LEC system, the City is able to add GHG-reducing technologies, such as the solar array on the library, as they become available.

6. Sources and Links

- CanmetENERGY Community Energy Case Study
- City of North Vancouver Lonsdale Energy Corporation
- Climate & Energy Action Awards – Lonsdale District Heating
- Corix Utilities Case Study North Vancouver – Lower Lonsdale District Energy System Project
- *Renewable Resources: Regulatory Initiatives* (Brian E. Taylor, Paper 4.1 Green Building Initiatives, Continuing Legal Education Society of British Columbia, October 2009)
- *Small Growth Big Opportunities* (Glenn Stainton, Vice President Operations Lonsdale Energy Corporation presentation October 13 2009 to District Energy Vancouver Board of Trade Sustainability Committee)

Interviews with:

Ben Themens, Director Lonsdale Energy Corporation

Photo credit: Lonsdale Energy Corporation

Appendix A: Projects/Utilities Reviewed for Potential Case Studies

Single Ownership Projects

Name	Location	Pop.	Project / Utility?	Elec, Heat Both	Joint Venture	Project Lead	Joint Ownership	Operating Agreement	Approx. Length of Operation	Number of Customers	Revenue Sources	Energy Source
NOTE: To generate a focus on smaller communities and projects with a track record, the 'population' and 'length of operation' categories have been colour coded either green (go); yellow/orange (caution) or red (stop). Red and orange highlighting may be a reason to exclude a project/utility as a case study.												
Projects - Not Joint Ventures												
District of Lake Couty Micro-Hydro Project (DLC), in drinking water supply system	Lake Country	12,000	P	E	**N**	LG	**No**	**No Operated by LG**	2 yrs	400 homes	$1.1m - loans; $1.9m Gas Tax - Innovations Fund; $512K grant Gas Tas Community Works Fund; $500K loan Green Municipal Fund. once debt paid off annual net revenus to be deposited in Climate Action Fund.	hydro
T'souke First Nation Solar hotwater and photovoltaic	T'Sou-ke Nation	160	P	B	**N**	FN	**No**	**No**	3 yrs	25 homes; 3 community buildings	$1.5m from 15 governmental and non-profit sources .	solar hw & ph
Wood Biomass at the Lillooet Recreation Centre	Lillooet	2,400	P	H	**N**	LG	**No**	**No**	1 yr	1	$467k from Gas Tax Agreement General Strategic Priorities and Innovations fund; $147k from the Rec Centre Capital Reserves; $50,000 via annual Gas Tax funds.	biomass
Saanich Peninsula WWTP effluent heat Recovery	CRD	340,000	P	H	**N**	LG	**No**	**No**	1.5 yrs	1 Pool saving >$100k in nat gas	$2.98m from Gas Tax Innovations Fund and self-funding: total cost $3.3m; 30 yr payback.	heat recovery
Kimberley micro hydro in water supply	Kimberley	6,700	P	E	**N**	LG	**No**	**No**	~3 yrs	sells electricy to bc hydro	Planning grant for feasibility study; Green Municipal Fund for micro-turbine and to replace chlorination system.	hydro
Burns Lake Arena	Burns Lake	2,120	P	H	**N**	LG	**No**	**No**	<1 yr	1	Total cost $419k: $126k Towns for Tomorrow	biomass
Bone Creek Run of River (Simpcw First Nation and TransAlta)	Blue River	240	P	E	**N**	UT	**No**	**No**	1 yr	Bone Creek has a 20-year PPA for all power.	PPA purchase agreement for 20 yrs. Contribution agreement via ecoEnergy for Renewable Power program.	hydro
Fort St. John	Fort St John	20,000	P	H	**N**	LG	**No**	**No**	1 yr	1	SolarBC	solar air heating
Geothermal City Halls	Langley, Kaslo, Elkford, Castlegar, Nakusp	106,000	P	H	**N**	LG	**No**	**No**	1-5 yrs	1	Various	geo
Richmond Oval Waste-Heat and Water Re-use	MV	198,000	P	H	**N**	LG	**No**	**No**	2 yrs	1	Olympic funding. The total cost of the project was $178m.	heat recovery
Cache Creek Outdoor Pool SHW&ASHP	Cache Creek	1,100	P	H	**N**	LG	**No**	**No**	2 yrs	1	Self-funded: 8 yr payback	solar & ashp
Vancouver Convention Centre sea water cooling heat pump system	Vancouver	651,000	P	H	**N**	LG	**No**	**No**	3 yrs	1	$883m expansion funded by Province ($540m), federal gov't ($222m), Tourism Vancouver ($90m) & projected revenues of $30m.	heat pump
Houston Rink and Leisure Centre	Houston	3,000	P	H	**N**	LG	**No**	**No**	4 yrs	1	$32k BC Hydro	waste heat
RD of Kootenay Boundary rec/pool/rink: efficiency, SHW, heat recovery	Kootenay Boundary	31,850	P	H	**N**	LG	**No**	**No**	5 yrs	1	$75k Recreational Infrastructure Canada program.	solar hw, heat pumps heat recovery
City of Kelowna landfill gas to electricty - microturbine pilot	Kelowna	122,000	P	E	**N**	LG	**No**	**No**	7 yrs	1	Excess electricity sold to FortisBC.	landfill gas
Golden Amenity Hubs campground and bike share	Golden	3,930	P	B	**N**	LG	**LG**	**No**	2 yrs	1	Self-funded?	geo solarhw solar pv
Catalyst Power Bio-methane Plant 110,000 gj /yr. Receives manure from 5 km radius.	Abbotsford	124,000	P	H	**N**	P	**PR UT**	**No**	1 yr	Sale of 'green gas' to FortisBC	Fixed price with FortisBC.	ag. waste

Joint Venture Projects

Name	Location	Pop.	Project / Utility?	Elec, Heat Both	Joint Venture	Project Lead	Joint Ownership	Operating Agreement	Approx. Length of Operation	Number of Customers	Revenue Sources	Energy Source
NOTE: To generate a focus on smaller communities and projects with a track record, the 'population' and 'length of operation' categories have been colour coded either green (go); yellow/orange (caution) or red (stop). Red and orange highlighting may be a reason to exclude a project/utility as a case study.												
Projects - Joint Ventures												
Cedar Road Landfill-Gas-to- Electricity Facility (Nanaimo)	Nanaimo	87,000	P	E	**Y**	LG	**Yes**	**Yes Cedar Road LFG & BCH EPA**	3 yrs	BCH EPA	Total cost $3.6m. RD of Nanaimo & Cedar Road LFG partnership. BCBN loan $400k+1.6m loan. $585k from FCM. RDN transferred carbon credits to FCM.	landfill gas
Run-of-river: Canoe Creek	Tla-o-qui-aht First Nation	345	P	E	**Y**	FN	**Yes**	**No Partnership: Tla-o-qui-aht FN (75%) and Swift Water Power Corp (25%)**	1.5 yrs	Electricity for 2,000 homes	ecoENERGY and Aboriginal Business Canada $1m funding for business plan, an EPA, and interconnection study.	hydro
Juan de Fuca Pool, Arena and Curling Club	CRD	52,200	P	H	**Y**	LG	**Yes**	**No**	10 yrs	3	Partnership of Colwood, Langford, Metchosin, Highlands, Juan de Fuca Electoral area and View Royal.	heat recovery
Hartland Landfill Gas Utilization Project	CRD	340,000	P	E	**Y**	LG	**PPP**	**Yes P3 w Maxim and CRD**	8 yrs	Enough for 1,600 homes	BCH EPA. CRD 1.9 million; Maxim $800k. CRD royalties are $250,000 to $2 million+ over the 20-year project life,depending on quantity of power.	landfill gas
Run-of-river: China Creek	Port Alberni	18,000	P	E	**Y**	FN	**No**	**Yes Upnit Power Corp - FN,LG,Synex partnership**	7 yrs	2,400 homes per year (6,000 at peak)	$8.5m debt syndicate via VanCity Capital: BCH EPA plus provincially-funded study, federal funding for planning, hydro survey & Ecotrust Capital $250k loan.	hydro
Eagle Lake Micro hydro project	West Vancouver	42,130	P	E	**Y**	LG	**No**	**Yes (Pacific Cascade Hydro)**	9 yrs	Equiv to 90 single family homes	District of West Vancouver: $328k. BCH EPA.	hydro
Burns Bog Landfill Gas Collection	Vancouver	651,000	P	B	**Y**	LG	**PPP**	**Yes Maxim**	8 yrs	Greenhouses 100,000 GJ/yr heat and BCH EPA-5.5MW/yr	Maxim invested $10m. Vancouver will receive revenues of approx. $400k per year over 20 yr contract.	landfill gas
Solar Colwood (solar, ductless heat pumps, EV's)	Colwood	16,720	P	B	**Y**	LG	**No**	**No**	1 yr	NA	3.9m from Natural Resources Canada; in-kind from Royal Roads, BC Hydro, & T'Sou-ke FN.	solar ashp

Utilities – Single Ownership and Joint Ventures

Name	Location	Pop.	Project / Utility?	Elec, Heat Both	Joint Venture	Project Lead	Joint Ownership	Operating Agreement	Approx. Length of Operation	Number of Customers	Revenue Sources	Energy Source
NOTE: To generate a focus on smaller communities and projects with a track record, the 'population' and 'length of operation' categories have been colour coded either green (go); yellow/orange (caution) or red (stop). Red and orange highlighting may be a reason to exclude a project/utility as a case study.												
Utilities - Not Joint Ventures												
Westhills Langford DE Sharing System	Langford	22,500	U	H	**N**	LG	**No**	**Yes. Sustainble Services Ltd. (sub of Westhills Land Corp.)**	3 yrs	200	Private investment of $3m (about $15k per home). Energy savings expected to pay back the additional capital costs in 10-15 yrs.	geo
Ty Histanis DE energy geoexchange (Tla-o-qui-aht First Nation). Only FN DES in Canada. Geothermal plant operates via hydro electricity.	Tofino	345	U	H	**N**	FN	**No**	**Yes**	1 yr	10 homes, 1 community building as of 2010. Up to 215 in total.	ICE Fund investment $750k. Total project value - $3m. An EQuilibrium project supported by Natural Resources Canada and CMHC.	geo & hydro
FinkMachines in Enderby - Biomass DE	Enderby	2,900	U	H	**N**	UT	**No**	**No Private utility**	1 yr	11	Private via Fink Machines	biomass
Sun Rivers Community Development Corporation : Initial partnership between Tk'emlúps FN, federal government and developer.	Kamloops	85,000	U	B	**N**	P	**No**	**No Corix owns and operates**	12 yrs	Around 600 now, 2000 eventually	Standard development financing.	geo
Whistler Athlete's Village DES	Whistler	10,000	U	H	**N**	LG	**No**	**N**	Since 2007?	Phase 1: 300 units (now) Phase 2: 600 units (planned)	DE cost of $4.1m was absorbed into total building costs, which were shared by Province & Vancouver Olympic Committee ($35m), RMOW ($8m) and the MFA ($100m loan). RMOW received a 2 yr extension to repay a MFA loan.	waste heat
City of Richmond Alexander DEU	MV	198,000	U	H	**N**	LG	**No**	**Yes**	<1	~250 units (1 development)	$4m capital funding City of Richmond	geo
Southeast False Creek NEU	MV	651,000	U	N	**N**	LG	**No**	**No**	2 yrs	In 2020: 560k m2 of space	$10.2m Gas Tax Fund; 20 year loan for $5m from Green Municipal Fund; self-funded $17.5m via own Capital Financing Fund.	heat recovery
Geo-exchange District Energy Utility for Upper Gibsons	Sunshine Coast	4,100	U	H	**N**	LG	**No**	**No**	2 yrs	Phase 1: 100 units	$1.4m system:$244m Island Coastal Economic Trust; $325m Innovative Clean Energy Fund; $256k Gas Tax Agreement; $190k Gibsons; $385k from developer.	geo
Lonsdale Energy Corporation	MV	51,000	U	H	**N**	LG	**No**	**No**	8 yrs	11+ buildings	$4m GMF; $204k Rural Infrastructure Fund for solar hw	natural gas & solar
Nelson Hydro Electric Utility	Nelson	9,800	U	E	**N**	LG	**No**	**No**	Since 1892	4,400+	Historic	hydro
Revelstoke Community Energy System	Revelstoke	7,300	U	H	**N**	LG	**No**	**N**	7 yrs	Several commercial and institutional buildings, including a school & community centre.	RCFC Holding Co. $1.25M; City Pref Share Purchase $1.20M; FCM GMF Loan @ ~3.5% $1.35M; Revelstoke Credit Union $1.00M; FCM GMF Grant $1.81M; Towns for Tomorrow grant $0.38M= Total $6.99M	biomass
City of New Westminster Electrical Utility, Kelowna Electric Utility, Grand Forks Electric Utility	MV	4,000 - 68,000	U	E	**N**	LG	**No**	**N**	long term	~ 200,000	These long term utilities do not generate their own electricity.	various
Utilities - Joint Ventures												
Dockside Green Community Energy System	CRD	84,000	U	H	**Y**	3	**Y**	**Yes. Corix contracted by DGE for operation, maintenance and customer service.**	Since 2007, but not on biomass	About 200 now; 1,100 at completion	Cost: $6.1m:federal Technology Early Action Measures program ($1.5m). Dockside Green Energy LLP (DGE) joint partnership of VanCity Capital Corp., FortisBC and Corix.	biomass

Appendix B: BC Examples by Governance Option

The examples in the table below demonstrate five governance options for renewable energy projects, and operational BC examples of each. Main sources of financing and funding are identified.

	Kimberley Micro Hydro in Water Supply Project *	Gibsons geoexchange district energy system	Revelstoke Community Energy Corporation Utility – biomass district energy system	Kelowna Landfill Gas to Electricity Microturbine Pilot Project	Lake Country Micro Hydro in Water Supply Project	Burns Lake Arena Biomass Project	Lonsdale Energy Corporation Utility (City of North Vancouver) – natural gas district energy system *	Nanaimo Landfill Gas Project *	China Creek – run-of-river hydro (First Nations, private sector, and local government partnership)	Fink Enderby Biomass District Energy Utility *	Sun Rivers Community Development Corporation geoexchange	Ponderosa Pincushion geoexchange	Dockside Green biomass district energy system	Dawson Creek Wind Energy Cooperative *
Governance model:														
• Full municipal ownership	X	X	X	X	X	X								
• Full Municipal ownership with operating agreement							X							
• Public Private Partnership (not full municipal ownership)								X	X					
• Private company / utility ownership										X	X	X	X	
• Community Energy Cooperative														X
Financing / funding sources:														
• FCM GMF grant	X		X				X	X	X					
• FCM GMF loan			X				X							
• Gas Tax		X				X								
• Gas Tax – Community Works Fund						X								
• Towns for Tomorrow (expired)			X			X								
• BC Bioenergy Network loan & investment								X						
• Innovative Clean Energy Fund (expired, but may return)		X						X						
• Community Action on Energy & Emissions (expired)		X												
• Infrastructure Planning Grant		X						X						
• Local economic trust		X												

	Kimberley Micro Hydro in Water Supply Project *	Gibsons geoexchange district energy system	Revelstoke Community Energy Corporation Utility – biomass district energy system	Kelowna Landfill Gas to Electricity Microturbine Pilot Project	Lake Country Micro Hydro in Water Supply Project	Burns Lake Arena Biomass Project	Lonsdale Energy Corporation Utility (City of North Vancouver) – natural gas district energy system *	Nanaimo Landfill Gas Project *	China Creek – run-of-river hydro (First Nations, private sector, and local government partnership)	Fink Enderby Biomass District Energy Utility *	Sun Rivers Community Development Corporation geoexchange	Ponderosa Pincushion geoexchange	Dockside Green biomass district energy system	Dawson Creek Wind Energy Cooperative *
• NRCan CanmetENERGY Technology Centre equipment lease				X										
• NRCan Technology Early Action Measures													X	
• Western Economic Diversification									X					
• Municipal debt/equity		X	X		X		X	X	X					
• Private utility / company							X	X	X	X	X	X	X	X
• Local credit union			X											
• Cooperative members														X
• First Nations									X					

The examples in the table above are just a small sample of the numerous renewable energy projects in BC. In particular there are many BC examples of renewable energy projects with Full Municipal Ownership or Private Company / Utility Ownership, and some additional examples of Public Private Partnerships and projects with Full Municipal Ownership with Operating Agreements. There is only one known BC example of a Community Energy Cooperative.