Whitehorse Community Energy Project

Community Energy System
Feasibility Study Report

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Submitted to:

YUKON ENERGY CORPORATION
David Morrison
President and Chief Executive Officer
2 Miles Canyon Rd.
Whitehorse, YT Y1A 6S7

Prepared by:

FVB ENERGY INC

Suite 350, 13220 St Albert Trail NW
Edmonton, AB T5L 4W1

1 Executive Summary

FVB Energy Inc. (FVB) has executed this comprehensive feasibility study for the steering committee comprised of Yukon Energy, City of Whitehorse, Yukon Cold Climate Innovation Centre, Energy Solutions Centre, and the Government of Yukon. The general intent is to determine whether a Community Energy System (CES) in Whitehorse is economically and technically feasible.

A CES delivers heat energy to several buildings from a central source, thus eliminating the need for individual boilers at each building and providing a platform to incorporate multiple energy supply options. The principal advantage of a CES is to enable customers to access alternative energy sources, which may be produced locally, and are subject to lower, more stable cost structures. Without a CES, it is usually neither possible nor practical to achieve access to alternative energy sources on a building by building basis. Other benefits include reduced point-use pollution, increased fuel source options, and greater operational synergies.

This study began by identifying key potential customers; the thermal potential for CES in Whitehorse. Multiple buildings within Whitehorse were visited and evaluated for compatibility to a hot water CES. These buildings were divided into six zones, and combined into eleven potential CES development scenarios. A screening analysis was undertaken to determine the most economic scenario to develop a CES.

Of the eleven scenarios investigated, five (5) scenarios resulted in attractive CES opportunities based on a medium temperature hot water distribution system. Based on the screening results, and with steering committee consultation, Scenario 11 was chosen as the most favourable CES solution for Whitehorse. This scenario highlights 43 key buildings to be connected to a CES located along Lewes Boulevard, Hospital Road and the Downtown Core. The total diversified peak heating load of this key scenario is estimated at 14.6 MW_{th} and requires 41,100 MWh of heating energy.

There were two scenarios that did not make reasonably good candidates for development, Scenario 5 Airport Road and Scenario 6 Canada Games Centre. The screening does not preclude development of a CES around Scenarios 5 and 6; it simply states that as envisioned, they are not viable. There may be permutations of these scenarios that are more attractive or there may be ways to incorporate these into other scenarios.

After selection of the preferred CES scenario, an analysis was undertaken to evaluate several competing energy supply options. The energy supply options screened include concepts using wood-based biomass, liquefied natural gas (LNG), and the status-quo fuel oil. The production technologies included combinations of natural gas boilers, fuel oil boilers, biomass boilers, Organic Rankine Cycle electrical production, and reciprocating engine cogeneration.

All of the energy supply alternatives considered three energy centres servicing the CES; existing capacity from the hospital (P1), capacity adjacent to the existing YE power plant consisting of peaking boilers and alternative energy capacity (P2), and a downtown back-up energy centre consisting of one fuel oil boiler (P3). The recommended combination of energy centres provides the following:

- Allows the CES system to develop while minimizing early capital expenditures (P1)
- With 1/3 of the overall required capacity, provides the majority of the CES required heating energy using alternative energy capacity at (P2) which is capital intensive but has low fuel costs
- Utilizes inexpensive boiler technology for peaking capacity (P2)
- Utilizes inexpensive boiler technology with fuel storage for back-up capacity (P1 and P3)
- Provides a very reliable and robust system with multiple plants located at the three ends of the system

The energy screening developed an estimate of the capital costs and annual costs associated with the energy centre (P2) located near the existing Yukon Energy power plant.

The ranking performed was based on the following:

- Fuel resource utilized
- Total annual cost of heating production per unit of heating energy provided
- Greenhouse Gas (GHG) savings estimates based on the difference between the developed case and the “business as usual” case
    - Business as Usual assumes all heating and electricity generation is generated using fuel oil

Further to the quantitative measures, the energy screening also ranked the energy sources based on YE’s Energy Planning Principles, as developed at the 2011 Charrette.

There were two energy supply options pursued to evaluate for the business case and technical concepts:

- Alternative 4 - Biomass system utilizing woodchip fuel source in combination with an Organic Rankine Cycle (ORC) to produce electricity.
- Alternative 6 - Reciprocating engine cogeneration (heat energy and electricity) with liquefied natural gas (LNG) input fuel.

These two options were chosen based on their ability to produce low cost thermal energy and their qualitative ranking.

Some of the other key outputs of the energy supply screening and sensitivities performed around these screenings were:

- Woodchip biomass is an attractive and local energy supply option for the community, with significant GHG emission reductions compared to status-quo fuel oil boilers.
  - Fuel price sensitivities (+/- 20%) resulted in less than +/- 20% effect on the price of delivered thermal energy. This option offers price stability that limits the project's sensitivity to fuel commodity price.
- Woodchip biomass in combination with ORC electrical production (Alternative 4) could result in a reduction of approximately 18,000 tonnes of $CO_{2\ eq}$ greenhouse gas emissions (GHG).
- Wood pellet biomass is an attractive environmental solution; however the fuel cost makes it less feasible than the woodchip alternatives.
- Reciprocating engine cogeneration using LNG as a fuel source has the ability to produce inexpensive thermal energy.
  - If it makes economic sense to bring LNG into the community to generate power, then it could be used as a fuel source for a CES that could be at or below the cost of thermal energy produced from wood waste.
  - The sensitivities performed around the price of LNG show that the cost of thermal energy at + 20% results in a higher thermal energy cost when compared with building-as-usual cost using fuel oil. This represents a significant risk to the proposed CES system.

Capital costs were developed for Scenario 11, the recommended CES option, using a wood chip fuelled biomass combustor with ORC (Alternative 4) and an LNG fuelled cogeneration concept (Alternative 6). The costs summarized in the table below were used as inputs into the business case.

	Alternative #4 Biomass c/w ORC	Alternative #6 LNG Cogeneration
Energy Centres	$27,778,000	$23,989,000
Distribution Piping	$16,066,000	$16,066,000
Energy Transfer Stations	$7,195,000	$7,195,000
Total Capital Costs	**$51,039,000**	**$47,250,000**

The capital cost includes 8,700 trench metres of buried, pre-insulated hot water piping, as well as the cost to connect 43 customer's buildings.

Although the preferred CES solutions represent a significant capital investment, the developed business plan proposes a phased approach to minimize the capital risk. Part of this risk is also mitigated by the fact that a large amount of the proposed buildings are government and public sector buildings (42% of the 43 buildings), which represent a more likely connection commitment in the early phases of the project.

A financial model was created to determine the business case of the preferred CES solutions. In addition to the capital costs and phasing described above, operating costs were developed. Other general and financial assumptions needed for the financial model were agreed upon with Yukon Energy. The outputs of the financial model for the preferred solutions are shown below.

	Levelized Rate	**Initial Rate**
2 x 3.5 MW_{th} biomass with ORC	\$197.14 /MWh_{th}	\$157.54 /MWh_{th}
7 MW_{th} biomass with ORC	\$215.16 /MWh_{th}	\$171.94 /MWh_{th}
7 MW_{th} biomass without ORC	\$220.17 /MWh_{th}	\$175.94 /MWh_{th}
LNG Cogen Engines	\$195.63 /MWh_{th}	\$153.13 /MWh_{th}

The LNG concept provided the lowest initial and levelized rate, somewhat better that the best biomass concept option. The outputs of the financial model were tested with a number of sensitivities. The key learnings for that analysis are as follows:

1. The CES is sensitive to capital costs so controlling construction costs is important.
2. Biomass concept options are not very sensitive to biomass price however the LNG concept is extremely sensitive to the price of LNG. If that LNG concept is chosen then controlling the price of LNG is critical.
3. The biomass concept options are not very sensitive to the electricity sale price however LNG concept is sensitive to the electricity sale price.
4. The CES preferred solutions are not sensitive to the build-out time required to connect the target customers.

A marketing plan has been developed to guide the process of securing commitments from the target customers. Term sheets have been created to present the CES offering to the largest target customers. An initial rate structure has been developed and compared to these buildings business as usual costs. The comparison shows a favorable advantage to customer's choosing to connect to the new CES.

Also included in the business plan are several identified risk factors the can affect the development of a CES as well as potential mitigation strategies.

In conjunction with this study, six typical ownership models were compared and contrasted. The findings were reviewed with Yukon Energy and the preferred model of 100% ownership through a corporation was selected. The owners/operators determination document is included separately from this study document.

A significant deliverable of this work scope was producing a conceptual design basis document to be used as the basis of establishing a detailed design for a system moving forward. The concept design includes the following:

- A general description of the major equipment and assumptions for each energy centre.
- Concept layouts, process single lines, and electrical single lines for each energy centre
- Description of recommended buried piping systems materials, proposed pipe routing, and preliminary pipe sizing.
- A general description of the energy transfer stations (ETS's) proposed to interface to the CES with the in-building space heating and domestic hot water systems.
- Flow schematics for the ETS concept for twelve of the proposed 43 buildings.

A successful CES requires satisfied customers, reliable and cost-effective energy sources and a reasonable outlay of capital. The work presented in this document clearly displays the fundamental principles, technical concepts, and business case on which a successful CES system and business can be established.

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Glossary

BAU	Business as Usual
CE	Community Energy
CES	Community Energy System
CHP	Combined Heat and Power
$CO_{2\ eq}$	Carbon Dioxide Equivalent
Cogen	Cogeneration
DPS	Distribution Piping System
EFLH	Effective Full Load Hours
ESA	Energy Service Agreements
ETS	Energy Transfer Station
FVB	FVB Energy Inc.
GHG	Greenhouse Gas Emissions
GJ	Gigajoule
HHV	Higher Heating Value
HVAC	Heating Ventilating and Air Conditioning
IG	Imperial Gallons
LDC	Load Duration Curve
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
MOU	Memorandum of Understanding
MURB	Multi-Unit Residential Building
MW_e	Megawatt Electrical
MWh_e	Megawatt Hour Electrical
MWh_{th}	Megawatt Hour Thermal
MW_{th}	Megawatt Thermal
O&M	Operation and Maintenance
ODT	Oven Dried Tonnes
ORC	Organic Rankine Cycle
PEX	Cross-Linked Polyethylene
ROE	Return on Equity
ROI	Return on Investment
TM	Trench Meters
YE	Yukon Energy Corporation
ΔT	Temperature Differential

2 Introduction

FVB Energy Inc. (FVB) has prepared this comprehensive feasibility study for the steering committee comprised of Yukon Energy, City of Whitehorse, Yukon Cold Climate Innovation Centre, Energy Solutions Centre, and the Government of Yukon. This document summarizes the in-depth assessment of technical and economic viability of a Community Energy System (CES) in the City of Whitehorse, and is intended to build on the pre-feasibility study (Stantec Consulting Ltd., March 8, 2010).

The Whitehorse CES Feasibility Study involves several aspects. The first portion is the load and energy analysis, where potential customers are determined, along with their respective heating requirements. This is followed by the CES pre-screening, where the loads are grouped into clusters with the intent of finding the optimal target zones for developing a CES.

Once the area for the CES has been chosen, the sources of energy to heat the system are selected. The technical concept is then developed encompassing all aspects of the previous stages and decisions. The technical concept establishes such details as pipe routing and sizing, energy centre capacity and major equipment sizing. This detail is then used to determine the capital associated with the technical concept.

The final portion of the work is the business case, which includes the business concept and business plan, marketing of the service to potential customers, and starting the process of securing customer commitments.

This document summarizes the process followed to define the proposed concepts. As such, the specific details evolve as the document progresses.

The deliverables are expected to provide a comprehensive evaluation of technical and business case viability and, assuming viability, a strong foundation and good direction leading into the next steps to develop an operational CES serving the City of Whitehorse.

2.1 Objectives

Yukon Energy's has a mandate to provide reliable and cost-effective energy services to its customers. The current electrical capacity provided by the hydroelectric generating station is not enough to meet the growing electricity demand. As part of a 20 year resource plan, they have identified a clean energy deficit by 2014 (Canmet ENERGY, 2011).

The Government of Yukon has expressed their interest in pursuing sensible energy expansion, energy security, and the use of local resources to meet the energy needs while meeting their climate change agenda (20% reduction in GHG's by 2020).

The City of Whitehorse has a sustainability plan targeting the reduction of GHG's and use of renewable resources.

As one solution to meeting these objectives the steering committee has tasked FVB to identify an alternative solution for providing heat and electricity by developing a CES alternative for Whitehorse.

The CES would potentially provide hot water thermal energy to a combination of municipal, territorial, federal, Crown Corporation and privately owned buildings in Whitehorse. A CES has the potential to assist Whitehorse meet its clean energy and sustainability objectives by providing the following:

- A thermal energy supply competitive with oil and propane
- The potential for significant reduction in greenhouse gas emissions
- The potential to use large quantities of locally sourced renewable fuels (e.g. biomass)
- Keeping more energy dollars within the local economy
- Providing a source of efficient electricity generation to feed into local electrical infrastructure
- Providing thermal energy supply equal to or more reliable than stand-alone heating systems
- Provide a thermal energy grid with the flexibility to grow and adapt to changing fuel supplies

2.2 Acknowledgements

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2.3 General

A CES delivers heat to a number of buildings from a central source. Whitehorse's conceptual system uses hot water heated via an energy source in one of three Energy Centres, delivered through underground insulated pipes to heat individual buildings.

Each building connected to the system receives energy through an energy transfer station (ETS). Having community-shared heat sources eliminates the need for individual boilers at each building.

The water returns to the Energy Centres to be re-heated and re-distributed. This closed-loop system allows for efficient production and distribution of energy.

In addition to providing thermal energy the CES will provide the opportunity to have a positive impact on the city's electrical production system. Three of the potential positive impacts are:

- The energy centre will have the opportunity to generate some efficient electricity in an arrangement known as cogeneration
- Competitive heating prices from the CES has the potential to reduce the reliance on electricity-based heating systems
- Provides an alternative to electric base board heating in future developments

Additional CES benefits include:

- Reduction in fossil fuel use and reduce reliance on non-local fuel sources
- Use local fuel resources providing a positive impact on the local/regional energy economy, and greater energy security Reduced need for boilers or fuel storage facilities within individual buildings
- Stable energy prices
- Substantial reduction in greenhouse gas emissions which allows business owners to inexpensively "green" their building
- Improved air quality and reduced point-use pollution
- Cost-effective means to implement the highest standards in emission reduction equipment
- Future flexibility - the energy heat source can be changed if a better option exists in the future

A CES would connect to customers in areas throughout Whitehorse, typically connecting to buildings that represent the largest heat requirements in the community.

2.4 Feasibility Study Outline

There are two main sections in the body of the report:

- Technical Concept Development, which includes:
  - Building Load and Energy Analysis - identifies the potential customers and their respective thermal loads and energy.
  - Community Energy System Concept Pre-Screening - screens different load centres (areas of the City) to identify the best opportunities to develop a community energy system.
  - Energy Source Technical Concepts - reviews and screens competing alternative energy supply options for the preferred CES concept.

- Business Plan, which includes:
  - Community Energy System Design Plan - general description of the preferred CES concept and its alternative energy supply.
  - Capital Costs
  - System Operation & Maintenance Costs
  - Building Business-As-Usual Costs
  - Business Case Results
  - Marketing Plan
  - Risk Management

The Appendices of the report contain supporting details referenced with the body of the report plus a Technical Design Basis Document (Appendix H). This document is a technical description of the proposed CES system that can be used as a basis to develop a detailed design. It includes the following:

- Energy Centre (EC) Design Basis
- Distribution Piping (DPS) Design Basis
- Energy Transfer Station (ETS) Design Basis

Technical Concept Development

The following section contains these subsections:

3 Building Load and Energy Analysis

4 Community Energy System Concept Pre-Screening

5 Energy Source Technical Concepts

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3 Building Load and Energy Analysis

3.1 Classification

One of the first steps in developing a successful CES is to identify potential customers. Some conditions that are representative of a good potential community energy candidate are:

- Larger sized buildings, for which a significant amount of energy would be displaced by a CES, such as hospitals, large condominiums, office buildings, etc.
- Buildings that already utilize hydronic heating systems.
- Buildings that are planning to replace boilers or heating sources.
- Future buildings in the planning or design stage.

The larger buildings were targeted and their heating requirements quantified. For the Whitehorse area, a minimum building area of approximately 1200 m^2 was determined as a viable customer. Most of the 20 buildings that were surveyed for CES compatibility (see 0) had hydronic heating systems meeting this criteria. The targeted buildings were then classified into groups consisting of:

- Multi-Unit Residential (MURB)
- Commercial
- School / Community
- Recreation / Pool
- Office
- Retail
- Hospital
- Hotel

Each of these groups represents a common type of building normally targeted for a CES. It is assumed that each building in a classified type will have similar load and energy consumption on a per square metre basis of floor area.

3.2 Heating Load and Energy Summary

After review of the pre-feasibility study (Stantec Consulting Ltd., March 8, 2010) and FVB's investigations, the zones established by the pre-feasibility study were considered reasonable and were re-used for consistency. Therefore six zones were re-evaluated as potential areas for a CES system, as shown in Figure 1.

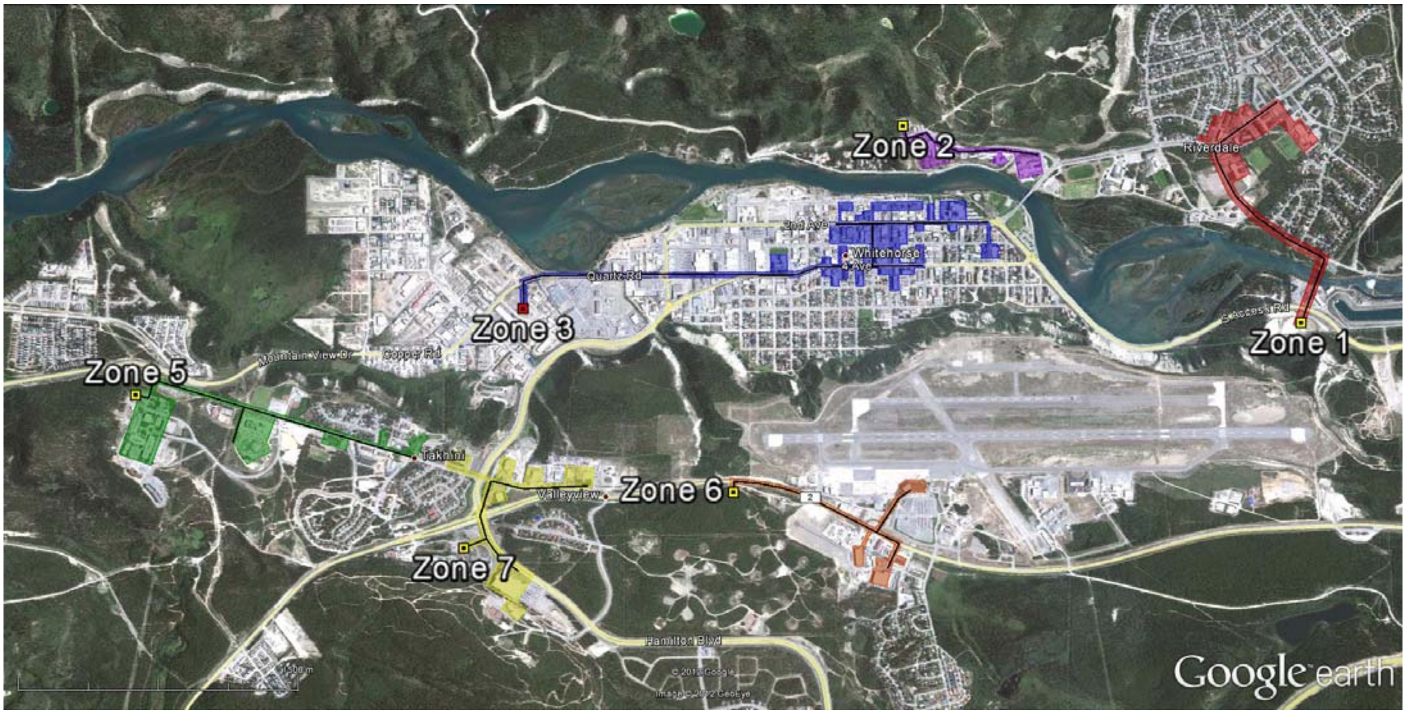

Figure 1 - Map of Zones Detailed in Pre-Screening

Further details of the preliminary loads and energy of all the building associated in each zone are provided in 0. These values are furthered refined at later stages of this study.

3.2.1 Zone 1 - Lewes Boulevard

Heading south along Lewes Boulevard, there is a large potential of customers in a fairly small area. Right along Lewes Boulevard between Takhini Avenue and Duke Road, there are a number of larger multi-unit residential buildings that, from the outside, look reasonable as potential CES candidates. Also in this area are a number of different schools and churches that are considered reasonable CES candidates. The total thermal load potential of identified buildings in this zone was estimated at 5.9 MW.

3.2.2 Zone 2 - Hospital Road

The area surrounding the Whitehorse general hospital was identified as a potential candidate due to the high loads that could be placed on a CES system. There are many CES systems throughout Canada that utilize the high demands of a hospital as the main customer or energy centre for a CES system. The Whitehorse General hospital is also surrounded by a few large office buildings that could be potential customers as well. The total thermal load potential of identified buildings in this zone was estimated at 3.3 MW.

3.2.3 Zone 3 - Downtown Core

The downtown core of Whitehorse is the largest and most diverse zone out of the six identified. With many commercial, office, institutional, and large residential buildings, there are many potential candidates that could be connected to a CES. In total, 45 buildings were identified as potential candidates for CES. The total thermal load potential of identified buildings in this zone was estimated at 15.6 MW.

3.2.4 Zone 4 - Quartz Road

The area was not investigated further due to far distances between marginal loads.

3.2.5 Zone 5 - Range Road

The Takhini area was identified due to the Yukon College, which represents a significant load that could be connected to a CES system. Surrounding the Yukon College are two correctional facilities, a few federal government buildings, and the Takhini Elementary school. The total thermal load potential of identified buildings in this zone was estimated at 4.1 MW.

3.2.6 Zone 6 - Airport

The airport zone consists of the airport terminal along with some surrounding hotels, commercial and office buildings. Also identified, were the Yukon Transportation Museum, the Beringia Interpretive Centre and a few Air North buildings, which consist of hangers and an administration building. The total thermal load potential of identified buildings in this zone was estimated at 3.0 MW.

3.2.7 Zone 7 - Canada Games Centre

The Alaska Highway and Two Mile Hill area is based around the large potential load of the Canada Games Centre. With an estimated load of 1.5 MW, the Canada Games Centre would account for approximately 45% of the total load in this zone. Also identified in the proximity of the Canada Games Centre were the Takhini Arena, Mount McIntyre, the newly constructed Public Safety Building, and a number of commercial buildings along Range Road. The total thermal load potential of identified buildings in this zone was estimated at 3.8 MW.

4 Community Energy System Concept Pre-Screening

With accurate estimates of the potential loads and energy from each zone, it is now important to determine which of these zones, or combinations thereof, provide the best opportunity to pursue a CES within Whitehorse.

The intent of the pre-screening analysis is to effectively and fairly make a comparison between the different zones identified. The results of this tool enable the selection of a preferred scenario to further develop. Though effort was made to provide justifiable input values and costs, these values are not finalized. However, they provide a level of accuracy high enough to make an educated and levelized comparison of each of the scenarios.

4.1 Scenarios

Each zone was further detailed for an accurate comparison. Energy centre locations were determined, distribution piping networks were laid out and building loads and locations were considered.

Energy centre locations were approximated based on discussions with the client and reasonable assumptions for the zones. Whenever possible a central location was considered to minimize distribution piping capital cost.

Distribution piping routes and appropriate sizes were determined. Smaller buildings that were far away from the distribution mains were no longer included. To better describe the distribution piping network, the piping was further categorized into one of three groups: transmission piping, mains or branch piping. Transmission piping connects the energy centre location to the first main branch or customer. The main lines generally follow roadways and connect groups of buildings together. The branch lines serve individual buildings.

Google Earth was used to approximate piping distances. Only the main distribution pipes are shown on the scenario schematics.

Based on FVB experience, buildings that are not above 100 kW of peak load are generally not economically feasible to connect to a CES. The total capital costs to connect these buildings outweigh the expected revenue from these customers. Once the CES has been established, these smaller buildings can be re-evaluated.

Further details of the energy centre locations, pipe routing and buildings connected in each scenario are found in Appendix B.

4.1.1 Scenario #1 - Lewes Blvd

The total connected load and energy of this scenario is 3.87 MW and 8,920 MWh from the identified potential of 5.9 MW and 13,600 MWh. The key loads in this area are the F.H. Collins Secondary School, Vanier Catholic Secondary School and the Skyline apartment buildings. However, F.H. Collins is currently under construction with a new, upgraded heating system and it was assumed that they would not be joining a Community Energy System at this time. The additional cost to distribute heat to Selkirk Elementary School limits its potential in this scenario.

The Lewes Boulevard area assumes an energy centre located across the Yukon River, by the existing power sub-station

The transmission pipe is approximated at 1,100 meters in trench length, crossing the Yukon River across the existing foot bridge. The system would also require approximately 580 meters of mains and 1,145 meters of branch piping. This scenario is comprised of fourteen buildings, requiring fourteen energy transfer station connections (see Appendix B for more detail).

4.1.2 Scenario #2 - Hospital Road

The Hospital Road scenario has a total assumed connected load of 3.18 MW and 8,510 MWh of heating energy. This scenario focuses on the high load buildings situated north of the Yukon River by the hospital. The key loads in this area are the Whitehorse General Hospital and the new Crocus Ridge building. This scenario does not include either #2 Hospital Road or #4 Hospital Road, due to their small size. Though newly constructed in April of 2011, the Crocus Ridge building was included in this scenario because it is felt that the existing system is compatible with a CES.

The Hospital Road scenario assumes an energy centre located in the same location as the hospital incinerator. This allows for a total transmission piping being only 70 meters in length. The system would also require approximately 750 meters of mains and 305 meters of branch piping. This scenario is comprised of four buildings requiring four energy transfer station connections (see Appendix B for more detail).

4.1.3 Scenario #3 - Downtown Core

The Downtown Core scenario has a total assumed connected load of 10.5 MW and 23,330 MWh of heating energy from the 15.6 MW and 35,000 MWh of identified potential loads and energy. This scenario focuses on the buildings situated between 1st and 5th Avenue in the core of Whitehorse's downtown. The key loads in this area are the Westmark Hotel & Conference Centre, Yukon Territory Government Administration Building, Elijah Smith Building, Hougen Centre, the Yukon Justice Building and Whitehorse Elementary school.

Any of the large buildings that employ a multitude of smaller rooftop heating or cooling units are not included in this scenario. These smaller units typically make the economics of retrofitting for a CES unfavourable in the early stages of CES development. Examples of this type of building are the Real Canadian Superstore and the Qwanlin Mall.

The Downtown Core scenario assumes the energy centre is placed in the light industrial section along Quartz Road, north of downtown. This requires approximately 1,600 meters of transmission piping. Locating the energy centre nearer to the downtown core would create a more attractive system.

The system would also require approximately 1,685 meters of mains and 2,240 meters of branch piping. This scenario is comprised of thirty-one buildings; requiring forty energy transfer station connections (see Appendix B for more detail). The higher number of energy transfer stations than buildings listed are due to how some buildings were defined. For example, the Hougen Centre was listed as one building to calculate the loads; however five individual energy transfer stations were assumed to meet the energy needs of the customers in this complex.

4.1.4 Scenario #4 - Range Road

The Range Road scenario has a total assumed connected load of 3.95 MW and 7,640 MWh of heating energy from the 4.1 MW and 8,100 MWh of identified potential loads and energy. This scenario focuses on the institutional and correctional facilities located along Range Road. The vast majority of this system load is from the Yukon College Campus. The other key facility in this area is the Federal Correction Centres.

The Range Road scenario assumes an energy centre located on the north side of the Yukon College Ayamdigut Campus. By placing the energy centre by the largest load, the downstream piping size and capital expenditure is reduced. As such, the transmission piping is 70 meters in length. The system would also require approximately 1,780 meters of mains and 480 meters of branch piping. This scenario is comprised of six buildings, requiring six energy transfer station connections (see Appendix B for more detail).

4.1.5 Scenario #5 - Airport

The Airport scenario has a total assumed connected load of 1.64 MW and 2,670 MWh of heating energy from the 3.0 MW and 5,700 MWh of identified potential loads and energy. This scenario focuses on the businesses located on the west side of the airport. The only major load on this system is the Airport Terminal itself.

A lot of effort went into selecting the best combination of buildings for this system. Ultimately, the Apartment buildings on the southwest side of the system, as well as the Yukon Transportation Museum, Yukon Beringia Interpretive Centre and Air North buildings were not included in this scenario.

The Airport scenario assumes an energy centre located on the government-owned land to the North of the system. This system requires an assumed 885 meters of transmission pipe, 280 meters of mains and 560 meters of branch piping. The optimized scenario is comprised of five buildings requiring five energy transfer stations (see Appendix B for more detail).

4.1.6 Scenario #6 - Canada Games Centre

The Canada Games Centre scenario has a total assumed connected load of 3.7 MW and 6,400 MWh of heating energy from the 3.8 MW and 6,600 MWh of identified potential loads and energy. This scenario focuses on the buildings located along the south end of Range Road, and the facilities near the Canada Games Centre. The key load of this scenario is from the Canada Games Centre and the Takhini Arena.

The Canada Games Centre scenario assumes an energy centre located on the land by the Environment Canada building and other government owned facilities. The transmission piping is limited to 130 meters in length. The system would also require approximately 1,105 meters of mains and 970 meters of branch piping. This scenario is comprised of eight buildings, requiring eight energy transfer station connections (see Appendix B for more detail).

4.1.7 Scenario #7 - Hospital and Lewes Blvd

The pre-screening analysis also looked at combining some of the promising zones to try to develop optimized scenarios.

The first of these combines Zone #1 - Lewes Boulevard with Zone #2 - Hospital Road. These zones have a total connected load of 7.41 MW and require 18,200 MWh of heating energy. This scenario focuses on the buildings on the east side of the Yukon River.

The key loads in this area are the Whitehorse General Hospital, Crocus Ridge, Skyline Apartments and Vanier Catholic Secondary School. As a main distribution line follows along Lewes Boulevard, this allows for the inclusion of the Selkirk Elementary School.

The Hospital and Lewes Blvd scenario assumes an energy centre located across the Yukon River by the existing power sub-station, similar to Scenario #1. This requires an approximate trench length of 1,100 meters for the transmission piping. The system would also require approximately 2,020 meters of mains and 1,670 meters of branch piping. This scenario is comprised of nineteen buildings requiring nineteen energy transfer station connections (see Appendix B for more detail).

4.1.8 Scenario #8 - Downtown Core and Hospital

The next scenario combines Zone #2 - Hospital Road with Zone #3 - Downtown Core. These zones have a total connected load of 13.73 MW and require 31,850 MWh of heating energy.

The key loads in this area are the Whitehorse General Hospital, Crocus Ridge, Westmark Hotel & Conference Centre, Yukon Territory Government Administration Building, Elijah Smith Building, Hougen Centre, the Yukon Justice Building and Whitehorse Elementary school.

The Downtown Core and Hospital scenario assumes an energy centre located in the industrial section of downtown, similar to Scenario #3. This scenario requires an approximate trench length of 1,600 meters for the transmission piping.

This scenario assumes crossing the Yukon River under the existing bridge to reach the loads near the hospital. The system would also require approximately 3,040 meters of mains and 2,615 meters of branch piping. This scenario is comprised of thirty-five buildings requiring forty-four energy transfer station connections (see Appendix B for more detail).

4.1.9 Scenario #9- Range Road & Canada Games Centre

The next scenario combines Zone #4 - Range Road with Zone #6 - Canada Games Centre. These zones have a total connected load of 7.65 MW and require 14,040 MWh of heating energy. The key loads in this area are the Yukon College Campus, Federal Correction Centres, Canada Games Centre and the Takhini Arena.

The Range Road scenario assumes an energy centre located on the north side of the Yukon College Ayamdigut Campus. Again, by placing the energy centre by the largest load, the downstream piping size and capital expenditure is reduced and the transmission piping required is limited to 70 meters in length.

The system would also require approximately 3,305 meters of mains and 1,475 meters of branch piping. This scenario is comprised of fourteen buildings requiring fourteen energy transfer station connections (see Appendix B for more detail).

4.1.10 Scenario #10 - Canada Games Centre - Revised

The next scenario looks at Zone #6 - Canada Games Centre, but includes a new 10,000 square foot Municipal Services Building, north of the buildings on Range Road.

This scenario has a total connected load of 4.54 MW and requires 8,150 MWh of heating energy. The key load of this scenario is from the Canada Games Centre and the Takhini Arena.

This scenario assumes an energy centre located on the land by the Environment Canada building and other government owned facilities. The transmission piping is limited to 130 meters in length. The system would also require approximately 1,135 meters of distribution line and 1,235 meters of branch piping. This scenario is comprised of nine buildings requiring nine energy transfer station connections (see Appendix B for more detail).

4.1.11 Scenario #11 - Lewes Boulevard, Hospital Road and Downtown Core

The final scenario combines Zone #1 - Lewes Boulevard, Zone #2 - Hospital Road and Zone #3 - Downtown Core. This scenario is a combination of the three top rated individual zones. These zones have a total connected load of 16.35 MW and require 38,400 MWh of heating energy.

The key loads in this area are the Vanier Catholic Secondary School, Selkirk Elementary School, Whitehorse General Hospital, Crocus Ridge, Westmark Hotel & Conference Centre, Yukon Territory Government Administration Building, Elijah Smith Building, Hougen Centre, the Yukon Justice Building and Whitehorse Elementary school.

This scenario was further refined to reflect a more accurate business case. Of the total identified buildings, 47% of non-government buildings and 90% of government buildings were assumed to connect to the system proposed by this scenario.

This scenario assumes an energy centre located across the Yukon River by the existing power sub-station, similar to Scenario #1. This requires an approximate trench length of 1,100 meters for the transmission piping.

The pipe routing requires crossing the Yukon River across the existing foot bridge by the sub-station and across the Yukon Bridge. The system would also require approximately 4,500 meters of mains and 3,910 meters of branch piping. This scenario is comprised of fifty buildings; requiring fifty-nine energy transfer station connections (see Appendix B for more detail).

4.2 Payback Criteria

With the scenario parameters defined, it is now possible to define comparative costs for ranking purposes. This involves defining an estimated annual capital cost of constructing the system, the utility costs and operation and maintenance costs associated, as well as a preliminary estimate of the revenue that can be attained from customers. All scenarios assume the source of thermal energy is provided by a wood chip fuelled biomass heating system, with fuel oil peaking boilers. These values are for preliminary screening only and offer sufficient accuracy for use to determine a preferred scenario. Details of the assumptions are provided in Appendix B.

4.3 Pre-Screening Results

From these values, a simplified payback is determined, as shown in the table below. Further details are provided in Appendix B.

Table 1 - Simplified Payback Results using Wood Chips

Whitehorse Pre-Screening Scenarios		Simplified Payback
Scenario #1: Lewes Blvd	Zone 1	13.5 yrs
Scenario #2: Hospital Road	Zone 2	7.7 yrs
Scenario #3: Downtown Core	Zone 3	10.4 yrs
Scenario #4: Range Road	Zone 5	14.8 yrs
Scenario #5: Airport	Zone 6	75.0 yrs
Scenario #6: Canada Games Centre	Zone 7	18.0 yrs
Scenario #7: Hospital and Lewes Blvd	Zones 1 & 2	10.4 yrs
Scenario #8: Downtown Core and Hospital	Zones 2 & 3	9.6 yrs
Scenario #9: Range Road & Canada Games Centre	Zones 5 & 7	14.5 yrs
Scenario #10: Canada Games Centre - Revised	Zone 7	15.2 yrs
Scenario #11: Lewes Blvd, Hospital and Downtown Core	Zone 1, 2 & 3	9.5 yrs

The results show the following scenarios with realistic simple paybacks:

- Scenario #2 - Hospital Road
- Scenario #11 - Lewes Boulevard, Hospital and Downtown Core
- Scenario #8 - Downtown Core and Hospital Road
- Scenario #7 - Hospital Road and Lewes Boulevard
- Scenario #3 - Downtown Core

However, all but Scenario #5 - Airport and Scenario # 6 - Canada Games Centre make reasonably good candidates for a CES. This high level screening does not preclude development of a CES around Scenarios 5 and 6; it simply states that as envisioned, they are not viable. There may be permutations of these scenarios that are more attractive or there may be ways to incorporate these into other scenarios.

4.4 Preferred Scenario Selection

The screening results were reviewed with the steering committee and it was agreed to pursue Scenario 11. This scenario encompasses the top three zones (Zone 1, 2 and 3) identified for development of a community energy system. It represents the largest thermal load and allows for additional heating energy recovery and emission control options that may not be fiscally feasible with a smaller system.

The scenario has high concentrations of customer loads in the downtown core, but allows for the flexibility of positioning smaller Energy Centres at the hospital, by the current YE power energy centre and within the downtown core.

Though it represents the largest upfront capital, proper phasing considerations can limit the risk. This scenario also represents a large amount of government owned buildings which represent a more likely connection commitment in the early phases of the project.

The finalized list of loads and energy are inclusive of the identified best high value potential customers. These customers were used to establish a project cost and the technical concepts. However, this customer list is not finalized and will be further refined through the concept development and marketing process.

5 Energy Source Technical Concepts

The energy screening compares alternative technologies and fuel sources to supply the baseload heating for the preferred Whitehorse CES (Scenario 11). The general intent of the results is to aid in the selection of the preferred energy supply solution(s).

For the purposes of the screening analysis, the CES was sized to meet the space heating and domestic hot water loads for the Hospital Road, Lewes Boulevard and Downtown core as detailed in Scenario #11.

The recommended technical concept incorporates the use of three energy centre locations to maximize the use of existing infrastructure, phase in capital as required, and provide system reliability:

- Energy Centre #1 (P1) - Whitehorse General Hospital
    - Steam conversion peaking / back-up capacity from existing hospital system
- Energy Centre #2 (P2) - Yukon Energy
    - 2 units of peaking boiler capacity
    - ~ 6.0 MW_{th} installed alternative heating capacity (Source determined in energy source screening)
- Energy Centre #3 (P3) - Downtown core
    - 1 unit of back-up boiler capacity

The alternative heating capacity is used to provide the baseload heating to the CES. Proper sizing of the alternative capacity is required to optimize the amount of energy supplied by this capacity. The alternative capacity typically comes at a premium of three to five times the capital cost of straight boiler capacity but with a lower fuel & operating cost. In addition to its high capital cost the alternative capacities do not usually have the ability to turndown to the same level as boilers. Therefore, over sizing the alternative capacity can have a negative impact on the energy that can be provided at low system loads, and the business case.

For the purpose of this screening analysis, 6.0 MW_{th} was selected as an optimum alternate heating capacity at full build-out. This represents 43% of the total capacity (see load duration curves in Appendix C).

For the thermal load following options, such as biomass, LNG and ORC, the alternate heat source delivered in excess of 86% of the annual thermal energy. For the cogeneration options, the alternate heat source delivered 67% of the annual heating energy. The latter is less because cogeneration was only assumed to run in winter.

The capacity not provided by the alternative energy supply was assumed to be provided by boilers: natural gas or fuel oil boilers depending on the scenario.

Details on the assumed energy centre locations, zones, base assumptions and loads and energy used for this screening are detailed in Appendix C.

5.1 Energy Sources

Potential sources of primary energy for the CES have been evaluated. In discussions with the steering committee and a review of the local area resources, the alternative energy sources were limited to:

- Biomass sources (wood chips and wood pellets)
- Biomass sources with organic Rankine cycle cogeneration (wood chips and wood pellets)
- Liquefied Natural Gas using reciprocating engine combined heat and power
- Fuel Oil using reciprocating engine combined heat and power
- Heat recovery potential with existing oil-fired reciprocating engines

5.1.1 Biomass Combustion

Biomass combustors use wood residue as a fuel source to produce heat energy. The biomass concept involves using a locally available, renewable resource that is priced less than other alternatives. Resources that could be targeted as possible supplies include:

- Forestry residues - Typically from nearby mill operations
- Urban residues - Including locally generated residues from park and street tree maintenance programs, wood pallets, and other clean wood sources
- Wood Pellets - From nearby production source
- Wood Chips - From nearby burn sites; assumed to be the whole tree including branches and some foliage.

The technology associated with these energy centres are well established and proven. Biomass based community energy centres are common in Scandinavia and have been implemented in some recent Community Energy projects in Canada, including Revelstoke, BC (2005), Oujebougamou, QC (1994), and Charlottetown, PEI (1986). A large scale biomass system is operating in downtown St. Paul, Minnesota (2001), and one is planned for downtown Seattle, Washington.

5.1.2 Biomass with Organic Rankine Cycle (ORC)

ORC uses a heat source to heat an organic fluid that rotates a turbine that is directly coupled to an electric generator. After the turbine, excess heat can be recovered from the fluid in a condenser. ORC technology is not new and has been used in deep geothermal power plants, particularly in the USA.

The proposed concept uses a biomass system with a hot oil cycle as a heat source for the ORC module. Wood fuel is burned heating hot oil to a high temperature, which then exchanges heat to an organic fluid within the ORC unit. The fluid expands through a turbine producing shaft rotation to produce power in the same basic cycle used for steam electricity generation. The low pressure fluid is then cooled via a heat exchanger transferring its heat to the CES.

Figure 2 - Computer Rendering of a Typical ORC Module

Typical electrical efficiencies are less than 20%. However a large portion of the input energy can be captured for district heating, meaning the overall CHP efficiency is high.

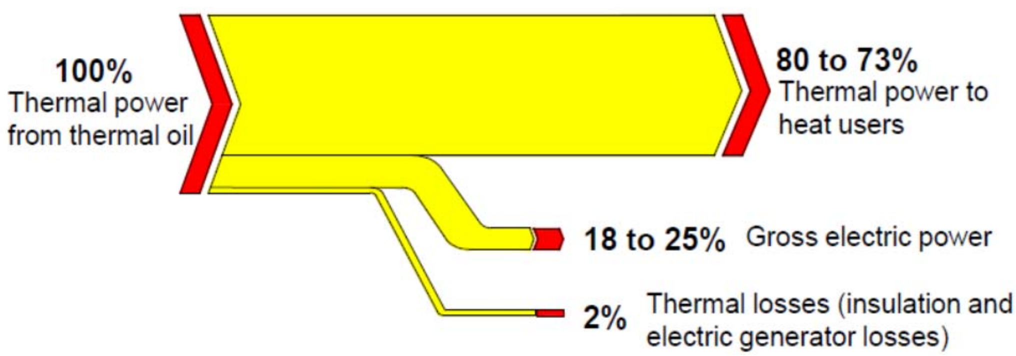

Figure 3 - Organic Rankine Cycle Efficiency[1]

This alternative assumes that the electrical generation is small enough that Whitehorse's electrical grid can absorb the additional electricity generation and community thermal energy can be supplied year-round from this source.

5.1.3 Cogeneration with Reciprocating Engines

Cogeneration recovers heat from electrical generation equipment. The cogeneration concept can be used with either existing or newly installed reciprocating engines. By cogenerating heat with electricity, maximum fuel efficiency can be achieved - see the figure below.

[1] Net efficiency of the ORC system must take into account the boiler efficiency that produces the thermal oil heat input into the cycle.

Figure 4 - Installed Jenbacher 616 2.4 MW_e Cogeneration Unit

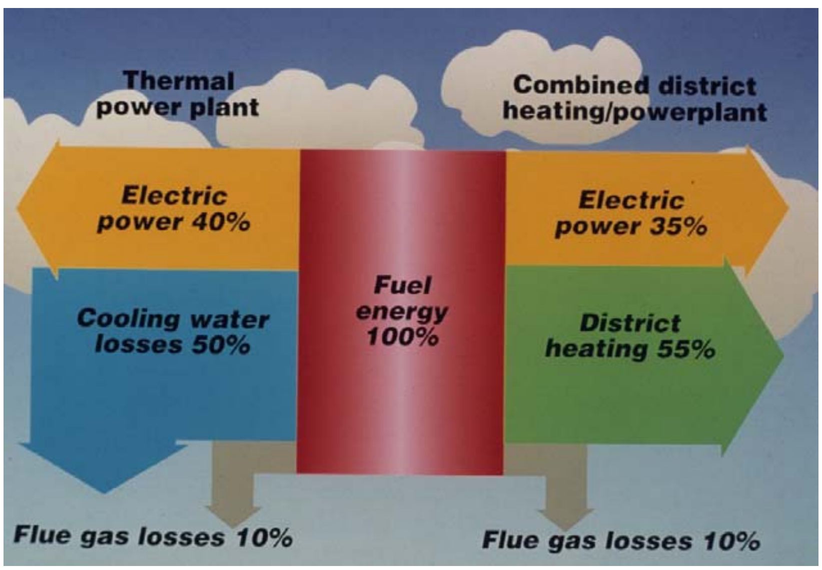

Figure 5 - Cogeneration Efficiency

A key component to the successful implementation of cogeneration is having a “heat sink” to sell the heat to, i.e. a Community Energy network. Typically, cogeneration is installed within an industrial process where there is a stable heat sink. The picture above indicates a 90% overall fuel efficiency; in Community Energy applications this is only achievable when the cogenerator is selected to closely match the heat load.

For the scale of this project, 6.0 MW thermal, reciprocating engines would be recommended. Similar concepts have been implemented in a number of Community Energy projects across Canada including Markham, Sudbury, Cornwall, and Hamilton.

To achieve a minimum 80% fuel efficiency at this scale, heat extraction will need to be optimized carefully, including from jacket water, and from the flue gas stream.

In the Whitehorse application, during the summer months, both thermal and electrical loads are lower and more electrical generation is available from hydroelectric sources. The cogeneration options are often electrical demand following, which often does not coincide with the thermal demand. In this case, the winter months receive higher demands both with respect to thermal needs and electricity generation deficit. As such, the cogeneration units are assumed to run during on-peak and off-peak hours during the winter months.

The cogeneration units are assumed to run for 4,890 hours annually. A preliminary analysis indicates that this concept can achieve a heat energy contribution to the CES of approximately 67% and fuel efficiency over 80%. This doubles the typical fuel to electrical efficiency of approximately 40%.

5.1.3.1 Liquefied Natural Gas

The cogenerators are similar in concept for the fuel oil and liquefied natural gas options. The main difference is in the fuel storage and the additional requirements to preheat LNG to become engine ready. It is assumed that enough low quality heat is available from the engines that additional fuel is not necessary to vapourize the LNG.

5.1.3.2 Fuel Oil

Cogeneration units that consume fuel oil increase the temperature of the engines, which is normally a disadvantage in efficiency. However, this increases the amount of high quality heat available for a CES.

The other important point is cost. Fuel oil engines will achieve higher electrical output compared to a comparable gas-fired engine block. The net result is a 10% savings in capital cost. These units have higher emissions than the LNG equivalent units.

5.2 Commodity Pricing

The fuel source data and pricing has been compiled from data and feedback provided by Yukon Energy, as well as previous reports disclosed during the 2011 Energy Charrette Process. The following table summarizes the fuel data.

Table 2 - Fuel Source and Cost Summary

Fuel Type	LNG	Fuel Oil	Wood Chips	Wood Pellets
Fuel Source	Kitimat (Future)	Edmonton	Fox Lake Burn Site	Quesnel
Cost per Volume	\$ 0.567 / m^3	\$ 1.00 / Litre	\$ 150 / Green Tonne	\$296 / Tonne
Cost per Energy Content	\$ 15.00 / GJ	\$ 25.70 / GJ	\$ 9.71 / GJ	\$ 17.02 / GJ

5.2.1 Liquefied Natural Gas

Liquefied natural gas is assumed to be sourced from various streams; (Yukon Energy Company, 2012) and (Fekete Associates Inc. and Vector Research, 2005):

- Trucked from Kitimat LNG - Expected operation in 2015
- Trucked from potential resource at Fort Nelson
- Trucked from potential local resource in Eagle Plains Field
- Alaska Highway Pipeline Project - Expected service in 2020-2021

There is a lot of excitement and uncertainty with regards to this fuel source. Large capital projects and feasibility studies are currently underway to promote this energy source as the next viable commodity to reduce emissions in areas short of localized resources.

Current prices are dependent on the cost of natural gas; which is valued at ten-year lows due to the surge of shale gas production. Three major players are proposing billions of investment dollars to develop exporting facilities in Kitimat, British Columbia. Once LNG is exported overseas, it is feasible that the commodity price will be based on the oil indexed contract rates used in Japan, Korea, Taiwan and China.

Current global LNG prices are surging to a 3-year high. With increased demand for this fuel projected, as well as a potential change to a more global market commodity price, the future price is expected to continue to rise. (Sethuraman, 2011)

A rate of $15 per GJ was provided by Yukon Energy for use in the screening analysis. Before the LNG can be supplied to the boilers, the liquid must be warmed from -162°C and vapourized. This heating of the fuel added 1.5% to the total annual heating energy of the system.

If LNG is brought into the city of Whitehorse for other projects, then synergies may exist to use this resource for the CES system. With the additional infrastructure required for this fuel, it is assumed not to be feasible to bring this resource in to the city specifically for the CES.

5.2.2 Fuel Oil

Current fuel oil is sourced from Edmonton and trucked in. Current prices are approximately $1.3 per Litre (Winter 2011/2012); however, the Government can obtain supplies for approximately $1 per Litre.

For the purposes of this study, the price of fuel oil is assumed to remain at current prices. As shown in the table below, the price has increased by approximately 30% in the last two years. This study makes no attempt to estimate the future value of this commodity, however price increases seem realistic.

Figure 6 - Fuel Oil Historical Price

5.2.3 Wood Chips

Based on the proposed biomass boilers and the heating values of the fuels, the following wood biomass volumes will be necessary to achieve the 86% annual energy target:

- Biomass Boiler = 10,300 green tonnes per year
- Biomass Boiler with ORC = 12,600 green tonnes per year

Specific sources and delivered prices for biomass options have been determined by Morrison Hershfield (Morrison Hershfield, 2011), and are described in the table below. This information was used in the energy source screening. This table was superseded and refined for the business case as more current and relevant information became available.

Table 3 - Wood Chip Resources

Source	Distance to Whitehorse	Tonnes of Available Wood Annually	Delivered Cost
Haines Junction	180 km	45,455	$142.03 /ODT
Fox Lake Fire (1998)	90 km	24,440	$115.87 /ODT
Minto (1995)	260 km	75,508	$165.28 /ODT
Average	206 km	145,403	$149.71 /ODT

There are strong supply options for wood biomass within the region, with harvest sites at local burn sites near Fox Lake and Minto, or at spruce beetle infested forest in the Haines Junction area. For the purpose of the screening, an average rate of $150 / oven dried tonne (ODT) from all of the local wood sources was utilized. The harvested biomass would be delivered and chipped within Whitehorse.

The main cost variance of the chipped wood options is the delivery charge. As shown above, the average cost of wood chips is conservative, since the proposed system has an annual biomass consumption which allows for the sole sourcing of chipped wood that is harvested from the Fox Lake site. This would significantly reduce the delivered fuel rate from the average assumed $150/ODT to $115.87 / ODT (Morrison Hershfield, September 14, 2011) or $7.50 / GJ.

5.2.4 Wood Pellets

Wood pellets are proposed to be trucked from the Pinnacle Pellets Plant in Quesnel, BC (as distributed through Taylor and Company based in Hay River, NT). These high-grade pellets are used to maximize the energy content of the pellets while providing cleaner burning and lower maintenance requirements.

The Government of Yukon tender price for supply and delivery of pellets to the new correctional centre is $326 per tonne delivered. It is assumed that a comparable price can be delivered for this project. However, cost and supply of this product is uncertain with major fires within the BC lumber mills dropping production in conjunction with increased demand from Europe. The Correctional Centre was able to lock into a 3-year locked-in price, but there is no guarantee this quote will reflect future prices.

The largest cost components for wood pellets are with pelletizing and transport. The Alaska Highway is prone to adverse road conditions during the winter that makes delivery a challenge. To remedy this, an oversized storage facility is recommended to secure a reliable feedstock.

Future local resources may become available, as the Yukon Wood Products Association has shown interest in developing a local pelletizing industry. There is also the development of a small start-up company, Yukon North Biomass Company, which has confirmed that it could up-size their production to meet an equivalent volume of compressed wood pucks.

As requested through discussion with the steering committee, the cost of wood pellets was reduced down to $296 per tonne delivered for the screening analysis.

5.2.5 Electricity Purchase Price

As per Yukon Energy, the average blended purchase price for electricity is $145.70 per MWh.

5.2.6 Electricity Sales Price

As per Yukon Energy, the expected sales price for all electricity generated is approximately $150 per MWh. With the expected shortfall in capacity, the price of electricity production is expected to rise. For this reason, a second scenario is illustrated that reflects an electricity sales price of $200 per MWh.

5.3 Energy Source Screening Criteria

The energy source screening analysis undertaken is based on the information assembled and with direction requested by the steering committee. FVB reviewed the following eight alternative energy supply options for the baseload thermal energy supply:

- High Efficiency Boilers - Liquefied Natural Gas
- Biomass Boiler - Wood Chip Fuel
- Biomass Boiler - Wood Pellet Fuel
- Biomass Boiler with Combined Organic Rankine Cycle - Wood Chip Fuel
- Biomass Boiler with Combined Organic Rankine Cycle - Wood Pellet Fuel
- Reciprocating Engine Cogeneration - Liquefied Natural Gas
- Reciprocating Engine Cogeneration - Fuel Oil
- Heat Recovery on Existing Generators - Fuel Oil

5.3.1 Total Blended Cost of Heating per MWh of Energy Supplied

The first basis for the energy source screening compares the total annual cost of each of these alternatives, in annual cost per MWh of energy supplied. This annual production cost includes a blended rate from both the alternative baseload plant and the peaking/back-up plants.

FVB established the following values to determine the total annual cost of heating production for each alternative energy supply options:

- Annual Fuel Costs
- Annual Electricity Cost
- Value of Electricity Produced
- Annual Operation and Maintenance Costs
- Annual Staffing Cost
- Annualized Energy Centre Capital

The capital costs used to determine the annualized energy centre capital allows for all equipment, installation, building, engineering, and contingency, but do not include the cost of land purchase, any costs associated with the distribution piping network, nor the energy transfer station connections within the customer buildings.

The accuracy of the capital cost estimates are a function of information known, and can be considered as “indicative”. This screening uses order of magnitude capital estimates for the energy supply options plus indicative equipment efficiencies for the screening inputs.

At the request of Yukon Energy we have assumed the liquefied natural gas will be available as a primary fuel supply at the Yukon Energy location for this screening. The remaining peaking and back-up heating supplied is assumed to be fuel oil based.

5.3.2 GHG Savings over Business as Usual (GHG)

FVB has considered the estimated greenhouse gas (GHG) emissions of each energy screening alternative, based on the emissions associated with the combustion of the fuel only. The greenhouse gas (GHG) savings estimates are the calculated difference in greenhouse gas estimates between the developed case and the "business as usual" case, offering an equivalent amount of thermal and electrical energy through conventional means.

In FVB's calculations, the amount of fuel and parasitic electricity consumption is estimated for each scenario. This amount is compared against how much fuel and parasitic electricity would be consumed to produce an equivalent amount of thermal (and electrical generation) assuming a business case where:

- Separate conventional stand-alone systems are used for generating electricity (diesel generators) and for heating individual buildings (fuel oil boilers):
    - Thermal energy is supplied from fuel oil boilers at 65% efficiency
    - Electrical energy is supplied from fuel oil driven generators at 34% efficiency

The difference in the amount of fuel/electricity consumed for each alternative is used to calculate the GHG Savings.

The following table shows the greenhouse gas emission savings over the equivalent business as usual cases for each energy screening alternative. The GHG emissions are expressed as tonnes of CO_2 equivalent:

Table 4 - GHG Savings over BAU Results for Energy Screening Options

	Alt #1 Central Plant LNG Boiler	Alt #2 Biomass Boiler - Wood Chips	Alt #3 Biomass Boiler - Wood Pellets	Alt #4 Biomass Boiler with ORC Cycle - Wood Chips
GHG Savings Over BAU	5,950 tonnes	13,100 tonnes	13,100 tonnes	18,240 tonnes

	Alt #5 Biomass Boiler with ORC Cycle - Wood Pellets	Alt #6 Reciprocating Engine Cogeneration - LNG	Alt #7 Reciprocating Engine Cogeneration - Fuel Oil	Alt #8 Heat Recovery on Existing Reciprocating Engine
GHG Savings Over BAU	18,240 tonnes	17,730 tonnes	13,780 tonnes	11,840 tonnes

These calculations assume the GHG emissions associated with the ***combustion of the fuel only.*** This method is commonly used, as it is the easiest to confidently quantify accurate results. For this reason, this method is also used by Canada to provide the UN Framework Convention on Climate Change estimates of our national GHG emissions.

Calculating the complete life cycle analysis on any energy stream is complex and often contains large biases and uncertainties in the results. This is beyond the scope of this study, therefore, no considerations are given to the GHG's associated with the exploration, raw material acquisition, fugitive emissions, raw material transport, energy conversion/fuel preparation, product transport or the impact of emission/waste stream clean-up, spills or disposals associated with any fuel source. If the project proceeds to the next phase, undertaking of a complete life-cycle GHG analysis would be a useful exercise to better understand and quantify the GHG emissions when compared to the status quo.

However, regardless of the results of a "Life Cycle Assessment" of the different potential fuel streams, it can be confidently stated that interconnecting electricity generation with a thermal source (CHP) using any fuel source is an improvement over the status quo as a result of improvement in fuel conversion efficiencies. A typical comparison between conventional power generation and boiler heat versus a combined heat and power system can be found below:

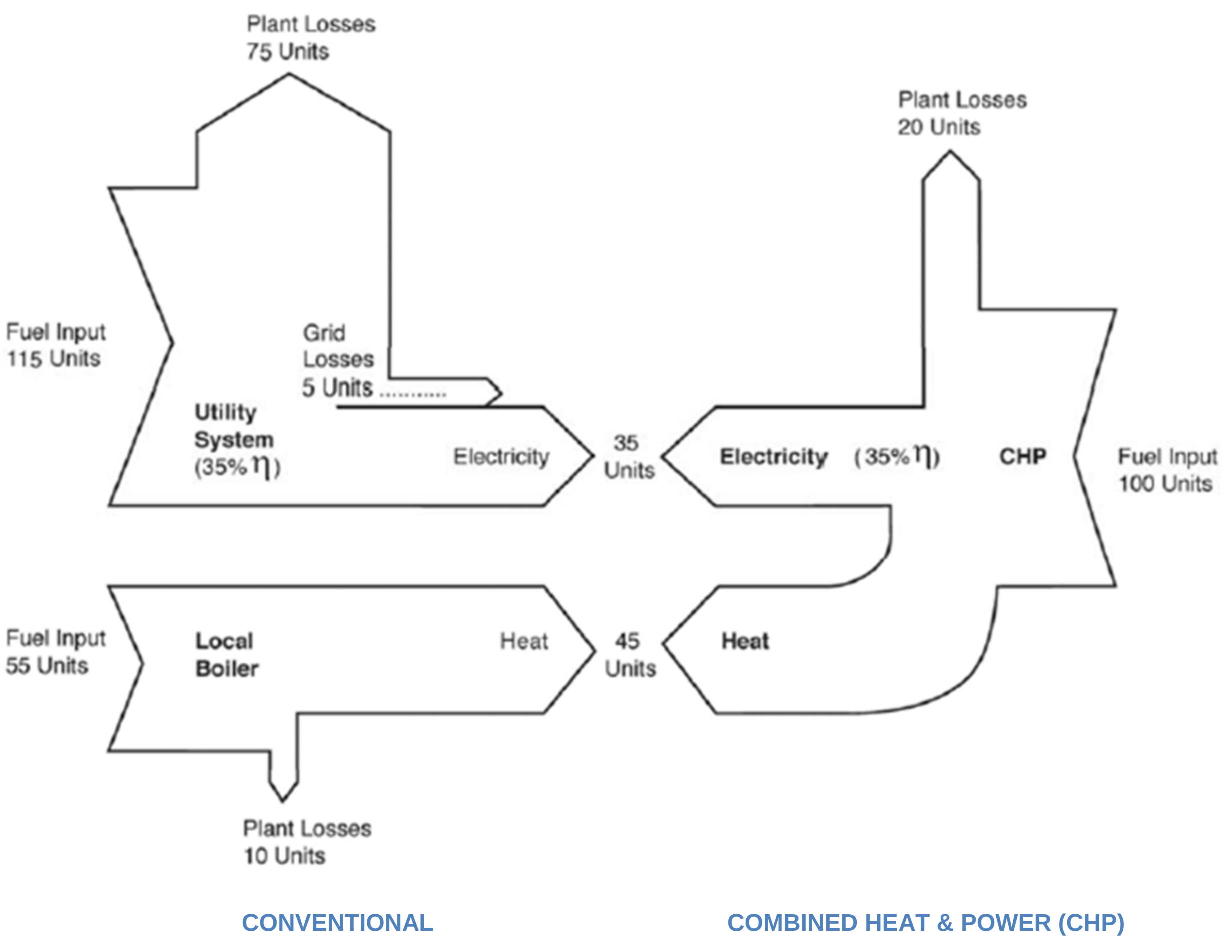

Figure 7 - Conventional Power Generation and Boiler Heat versus CHP (Meckler & Hyman, 2010)

As shown above in this generic example, 115 units of energy are required to produce 35 units of electricity. As well, 55 units of fuel input are required to produce 45 units of thermal energy in a high efficiency boiler. When compared to a CHP system, 100 units of fuel input can provide the same amount of output energy as 170 units of a conventional system.

Using the results of Alt #6 in comparison, the LNG generator alone has an efficiency of 34.2%, or 100 units of fuel input produces 34.2 units of electrical output. When the same engine is used with a thermal recovery system, 100 units of energy produces 34.2 units of electrical output and 29.9 units of high-grade thermal output. This raises the overall efficiency from 34.2% to 64.1%, or efficiency increase of over 87%.

5.3.3 Qualitative Analysis

In addition to this quantified criteria, the energy screening also considers the following qualitative criteria:

- Reliability
- Flexibility
- Environmental Responsibility

5.4 Results of Alternatives

The following tables are summaries of the developed cases using alternate sources of energy to provide the thermal energy needs of the preferred CES development (Scenario 11). The results are preliminary and suitable for screening purposes only.

Further details of the screening assumptions are found in the Energy Screening Memo in Appendix C. This appendix also includes the load duration curves used to determine the energy and fuel usage for each energy source alternative and concept schematics of Energy Centre #2 for each energy source alternative. Schematic diagrams for each of the energy supply alternatives can be found in Appendix C.5.

5.4.1 Alternative #1 - High Efficiency Boilers - Liquefied Natural Gas

This alternative heating scenario is assumed to be the base case for the energy supply options. Though it is not specifically recommended as an option, it is lowest capital solution screened. Fuel cost is the largest portion of the energy costs associated with this scenario.

Table 5 - Alternative #1 Energy Screening Summary

Criteria	Value	Comment
Resource	LNG	
Total Blended $/MWh Heating	$99 /MWh	Low cost option
Total Green House Gas Outputs	8,800 Tonnes	
GHG Savings over Business As Usual	5,950 Tonnes	Lowest GHG Savings

Some of the key benefits of this option are:

- Low operating, maintenance and capital cost
- Low performance risk

- Low public impact
- Low particulate emissions

Some of the key challenges for this option are:

- No alternate energy source used
- Small green house gas reduction
- Uncertainty with regards to supply and cost for LNG
- Thermal production only, no electrical production

5.4.2 Alternative #2 - Biomass Boiler - Wood Chips

The next scenario uses a local biomass stream and uses direct combustion to heat the circulating water for the CES.

Table 6 - Alternative #2 Energy Screening Summary

Criteria	Value	Comment
Resource	Wood Chips	Locally sourced
Total Blended $/MWh Heating	$104 /MWh	Slightly higher than Alt #1
Total Green House Gas Outputs	1,700 Tonnes	
GHG Savings over Business As Usual	13,100 Tonnes	

Some of the key benefits are:

- Stable and low fuel costs
- Uses a local fuel stream
- Low capital investment
- Reduction in greenhouse gas emissions
- Future potential use of mill residue streams or other community waste products
- Known and well-proven conversion technologies available

Some of the key challenges for this option are:

- Fuel handling challenges in the winter
- Cost of emission remediation
- Thermal production only

5.4.3 Alternative #3 - Biomass Boiler - Wood Pellets

This alternative uses delivered wood pellets as fuel for direct combustion biomass boilers.

Table 7 - Alternative #3 Energy Screening Summary

Criteria	Value	Comment
Resource	Wood Pellets	
Total Blended $/MWh Heating	$125 /MWh	Due to high fuel costs
Total Green House Gas Outputs	1,700 Tonnes	
GHG Savings over Business As Usual	13,100 Tonnes	

Some of the key benefits are:

- Consistent fuel input simplifies fuel handling and combustion process
- Reduction in greenhouse gas emissions
- Future potential use of mill residue streams or other community waste products
- Backward compatible to wood chips
- Known and well-proven conversion technologies available

Some of the key challenges for this option are:

- Fuel handling challenges in the winter
- Reliability of fuel delivery in winter
- Cost of emission remediation
- Thermal production only

5.4.4 Alternative #4 - Biomass Boiler with Organic Rankine Cycle - Wood Chips

This alternative provides combined heat and power generation. The biomass boiler produces hot oil that is exchanged with an organic fluid. The fluid is vapourized, and then expands across a turbine that generates electricity. The fluid then transfers heat to the CES, and condenses and cools the organic fluid.

Table 8 - Alternative #4 Energy Screening Summary

Criteria	Value	Comment
Resource	Wood Chips	Locally sourced
Total Blended $/MWh Heating	$99 /MWh	
Total Green House Gas Outputs	1,500 Tonnes	
GHG Savings over Business As Usual	18,240 Tonnes	Highest GHG savings

Some of the key benefits are:

- Stable and low fuel costs
- Produces approximately 6,800 MWh_e of electricity
- Highest reduction in greenhouse gas emissions
- Future potential use of mill residue streams or other community waste products
- Known and well-proven conversion technologies available

Some of the key challenges for this option are:

- Fuel handling challenges in the winter
- Cost of emission remediation
- More complex system with higher operational demand than direct combustion
- Highest capital cost

5.4.5 Alternative #5 - Biomass Boiler with Organic Rankine Cycle - Wood Pellets

This alternative is the same as Alternative #4, but with wood pellets as a fuel source.

Table 9 - Alternative #5 Energy Screening Summary

Criteria	Value	Comment
Resource	Wood Pellets	
Total Blended $/MWh Heating	$124 /MWh	
Total Green House Gas Outputs	1,500 Tonnes	
GHG Savings over Business As Usual	18,240 Tonnes	Highest GHG Savings

Some of the key benefits are:

- Stable and low fuel costs
- Produces approximately 6,800 MWh_e of electricity
- Highest reduction in greenhouse gas emissions
- Future potential use of mill residue streams or other community waste products
- Backward compatible to wood chips
- Known and well-proven conversion technologies available

Some of the key challenges for this option are:

- Fuel handling challenges in the winter
- Reliability of fuel delivery in winter
- Cost of emission remediation
- More complex system with higher operational demand than direct combustion
- High capital cost
- High biomass cost

5.4.6 Alternative #6 - Reciprocating Engine Cogeneration - Liquefied Natural Gas

This alternative assumes the purchase of new reciprocating engine electrical generators with waste heat recovery.

The cogeneration options assume that these units only run when electrical demand is high enough to warrant running the units. This screening assumes a run-time of 4,890 hours; however this may not match actual electrical demand which would affect the annualized cost of thermal energy.

The heat to vapourize the LNG from storage to fuel injectors is assumed to be provided by low-grade heat not utilized to heat the community energy flow.

Table 10 - Alternative #6 Energy Screening Summary

Criteria	Value	Comment
Resource	LNG	
Total Blended $/MWh Heating	$100 /MWh	Low cost option
Total Green House Gas Outputs	18,400 Tonnes	High GHG emissions
GHG Savings over Business As Usual	17,720 Tonnes	Due to displaced oil-fired electrical generation

Some of the key benefits of this option are:

- Large amount of electricity production
- Well proven technology with low risk
- Low public impact
- Low particulate emissions

Some of the key challenges for this option are:

- Highly dependent on commodity prices
- High green house gas emissions
- Uncertain supply and cost for LNG

5.4.7 Alternative #7 - Reciprocating Engine Cogeneration - Fuel Oil

This alternative is the same as Alternative #6, except that fuel oil is used.

Table 11 - Alternative #7 Energy Screening Summary

Criteria	Value	Comment
Resource	Fuel Oil	
Total Blended $/MWh Heating	$163 /MWh	Highest alternative
Total Green House Gas Outputs	22,400 Tonnes	Highest GHG emissions
GHG Savings over Business As Usual	13,770 Tonnes	

Some of the key benefits of this option are:

- Large amount of electricity production
- High amount of high-grade waste heat
- Well proven technology with low risk
- Excellent existing fuel storage capabilities
- Small footprint
- Low public impact

Some of the key challenges for this option are:

- Highly dependent on commodity prices
- High green house gas emissions
- High particulate emissions

5.4.8 Alternative #8 - Heat Recovery on Existing Generators - Fuel Oil

This alternative uses existing electrical generators with the installation of new heat recovery equipment.

Table 12 - Alternative #8 Energy Screening Summary

Criteria	Value	Comment
Resource	Fuel Oil	
Total Blended $/MWh Heating	$159 /MWh	Very high alternative
Total Green House Gas Outputs	24,300 Tonnes	Highest GHG emissions
GHG Savings over Business As Usual	11,830 Tonnes	

Some of the key benefits of this option are:

- Majority of capital already spent
- Large amount of electricity production
- High amount of high-grade waste heat
- Well proven technology with low risk
- Excellent existing fuel storage capabilities
- Low public impact

Some of the key challenges for this option are:

- Highly dependent on commodity prices
- Highest green house gas emissions of any option
- High particulate emissions
- Existing engine infrastructure is near the end of its assumed life

5.4.9 Results Summary

The key results are provided below, with a more detailed summary complete with a list of the base assumptions is provided in Appendix C.

Table 13 - Key Energy Screening Results

	Alternative #1 Standard Boilers *LNG*	**Alternative #2** Biomass Boilers *Wood Chips*	**Alternative #3** Biomass Boilers *Wood Pellets*	**Alternative #4** Biomass Boiler with ORC *Wood Chips*
Alternative Energy Centre Capital	N/A	$10,500,000	$10,500,000	$15,320,000
GHG Reductions over BAU (CO_2 eq)	5,950 Tonnes	13,100 Tonnes	13,100 Tonnes	18,240 Tonnes
Alternative Energy Cost of Thermal Energy	N/A	$ 85 / MWh_{th}	$ 109 / MWh_{th}	$ 79 / MWh_{th}
Total Blended Cost of Thermal Energy	$ 99 / MWh_{th}	$ 104 / MWh_{th}	$ 125 / MWh_{th}	$ 99 / MWh_{th}

	Alternative #5 Biomass Boiler with ORC *Wood Pellets*	**Alternative #6** Reciprocating Engine Cogeneration *LNG*	**Alternative #7** Reciprocating Engine Cogeneration *Fuel Oil*	**Alternative #8** Heat Recovery on Existing Generators *Fuel Oil*
Alternative Energy Centre Capital	$15,320,000	$15,000,000	$13,500,000	$2,400,000
GHG Reductions over BAU (CO_2 eq)	18,240 Tonnes	17,720 Tonnes	13,770 Tonnes	11,830 Tonnes
Alternative Energy Cost of Thermal Energy	$ 108 / MWh_{th}	$ 83 / MWh_{th}	$ 177 / MWh_{th}	$ 171 / MWh_{th}
Total Blended Cost of Thermal Energy	$ 124 / MWh_{th}	$ 100 / MWh_{th}	$ 163 / MWh_{th}	$ 159 / MWh_{th}

5.5 Increased Electrical Sales Price Scenario

The alternatives were also evaluated using an electricity sales price of $200 / MWh_e. The key results are provided in the table below, with a more detailed summary provided in Appendix C.

Table 14 - Energy Screening Results Comparison using Varied Electricity Sales Prices

Total Blended Cost of Thermal Energy	**Alternative #1** Standard Boilers *LNG*	**Alternative #2** Biomass Boilers *Wood Chips*	**Alternative #3** Biomass Boilers *Wood Pellets*	**Alternative #4** Biomass Boiler with ORC *Wood Chips*
Electricity Sale Price @ $150 /$MWh_e$	$ 99 / MWh_{th}	$ 104 / MWh_{th}	$ 131 / MWh_{th}	$ 99 / MWh_{th}
Electricity Sale Price @ $200 /$MWh_e$	$ 99 / MWh_{th}	$ 104 / MWh_{th}	$ 131 / MWh_{th}	$ 90 / MWh_{th}

Total Blended Cost of Thermal Energy	**Alternative #5** Biomass Boiler with ORC *Wood Pellets*	**Alternative #6** Reciprocating Engine Cogeneration *LNG*	**Alternative #7** Reciprocating Engine Cogeneration *Fuel Oil*	**Alternative #8** Heat Recovery on Existing Generators *Fuel Oil*
Electricity Sale Price @ $150 /$MWh_e$	$ 131 / MWh_{th}	$ 100 / MWh_{th}	$ 163 / MWh_{th}	$ 159 / MWh_{th}
Electricity Sale Price @ $200 /$MWh_e$	$ 122 / MWh_{th}	$ 61 / MWh_{th}	$ 125 / MWh_{th}	$ 121 / MWh_{th}

5.6 Fuel Cost Sensitivities

Further to the results of the base alternative energy screening, the tables below summarize the impact of ±20% fuel costs. Fuel costs assumed are as follows:

Table 15 - Varied Fuel Cost Values

Fuel Costs	Fuel @ +20%	Base Case	Fuel @ -20%
LNG	$18.00 /GJ	$15.00 /GJ	$12.50 /GJ
Fuel Oil	$1.200 /L	$1.000 /L	$0.833 /L
Wood Chips	$180.00 /Green Tonne	$150.00 /Green Tonne	$125.00 /Green Tonne
Wood Pellets	$355.20 /Tonne	$296.00 /Tonne	$246.67 /Tonne

The sensitivity results are summarized below:

Table 16 - Fuel Cost Sensitivity Summary of Results

Total Blended $/MWh of Heating	Alt #1 Central Energy Centre LNG Boiler	Alt #2 Biomass Boiler - Wood Chips	Alt #3 Biomass Boiler - Wood Pellets	Alt #4 Biomass Boiler with ORC Cycle - Wood Chips
Fuel @ +20%	*$112 /MWh*	*$114 /MWh*	*$139 /MWh*	*$110 /MWh*
Base Case	*$99 /MWh*	*$104 /MWh*	*$125 /MWh*	*$99 /MWh*
Fuel @ -20%	*$87 /MWh*	*$96 /MWh*	*$113 /MWh*	*$89 /MWh*

Total Blended $/MWh of Heating	Alt #5 Biomass Boiler with ORC Cycle - Wood Pellets	Alt #6 Reciprocating Engine Cogeneration - LNG	Alt #7 Reciprocating Engine Cogeneration - Fuel Oil	Alt #8 Heat Recovery on Existing Reciprocating Engine
Fuel @ +20%	*$141 /MWh*	*$128 /MWh*	*$205 /MWh*	*$205 /MWh*
Base Case	*$124 /MWh*	*$100 /MWh*	*$163 /MWh*	*$159 /MWh*
Fuel @ -20%	*$110 /MWh*	*$76 /MWh*	*$128 /MWh*	*$121 /MWh*

The provided rankings are based on cost of thermal energy only.

Table 17 - Fuel Cost Sensitivity Alternative Ranking

	Alt #1 Central Energy Centre LNG Boiler	Alt #2 Biomass Boiler - Wood Chips	Alt #3 Biomass Boiler - Wood Pellets	Alt #4 Biomass Boiler with ORC Cycle - Wood Chips	Alt #5 Biomass Boiler with ORC Cycle - Wood Pellets	Alt #6 Reciprocating Engine Cogeneration - LNG	Alt #7 Reciprocating Engine Cogeneration - Fuel Oil	Alt #8 Heat Recovery on Existing Reciprocating Engine
Fuel @ +20%	*2*	*3*	*5*	*1*	*6*	*4*	*8*	*7*
Base Case	*2*	*4*	*6*	*1*	*5*	*3*	*8*	*7*
Fuel @ -20%	*2*	*4*	*6*	*3*	*5*	*1*	*8*	*7*

From these results, the following conclusions can be made:

1. Alternative #4 - Wood Chip Biomass Boiler with ORC is the top-ranked alternative for the high fuel and base case fuel cost scenarios. Even with the price fluctuating ±20%, the blended annual heating only changes $21/MWh. This option offers price stability that limits the project's sensitivity to fuel commodity price.
2. Alternative #1 - Standard LNG Boilers is the second ranked alternative for all prices, and is competitive against all options. This alternative is not intended as a contending alternative, but is meant to provide a baseline to compare the other alternatives.
3. The lowest blended annual heating price is with Alternative #6 - LNG Cogeneration when the fuel is priced at -20% of the assumed commodity price. At $76/MWh, this is a very attractive alternative, but it should be noted that at a fuel price of +20% the cost of heating energy increases by $53/MWh.
4. The wood pellet and fuel oil alternatives (Alternatives 3, 5, 7 & 8) are consistently lower ranking options.
5. From the fuel cost sensitivity results, the direct combustion options for LNG, wood chips, wood pellet and Alternative #4 wood chips with ORC offer the best price stability.

5.7 Ranking According to YE's Energy Planning Principles

5.7.1 Affordability

This criteria ranks the scenarios based on the cost of the alternative fuel cost. The fuel is the largest component of the total utility cost to the customer. This ranking takes into consideration the stability of the fuel price.

5.7.2 Reliability

The CES will be designed to supply Whitehorse with a utility grade supply of thermal energy. At full build-out, if the largest unit unexpectedly shuts down, the system has enough back-up capacity installed to provide full capacity to its customers. The CES will have three energy centres with a minimum of two fuel sources (Alternatives 1 thru 6).

5.7.3 Flexibility

Inherently, CES's are flexible systems. The capital is built into the infrastructure required to supply heat to the customers. The energy heat source can be changed if a more attractive business model presents itself in the future.

The LNG cogeneration units lend themselves to burn any methane source of fuel. This could include biogas or synthesis gas provided locally from biomass or waste streams.

The biomass options can accept fuel from many biomass sources. This could include properly converted mill residue streams, waste from construction, or renovation and demolition waste.

5.7.4 Environmental Responsibility

In general, some of the primary advantages of a CES are to create a central heat source that allows for energy efficiencies, flexible fuel supply options and emission controls that are not fiscally feasible with multiple smaller systems. In this respect, all alternatives have a positive impact over the status quo: distributed oil boilers and electricity generated using oil-fired reciprocating engines.

The largest greenhouse gas emissions savings are seen with the electricity producing biomass options (Alternatives #4 & #5) and LNG cogeneration (Alternative #6).

However, the full life cycle environmental cost fuels are not included in these calculations. Exploration, raw material acquisition, fugitive emissions, raw material transport, energy conversion and relevant fuel preparation were not taken into account in the GHG savings calculations. Their order of magnitude varies depending on the extraction methods employed and the energy source used in the liquefying process; however, these are expected to be greater than those related to biomass harvesting and processing.

5.7.5 Ranking Summary

As per the Yukon Energy Charrette, the key energy planning principles were quantified and summarized below.

Table 18 - Ranking for Alternatives

Criteria	Alt #1	Alt #2	Alt #3	Alt #4	Alt #5	Alt #6	Alt #7	Alt #8
Affordability	4	4	2	4	2	5	1	1
Reliability	4	4	5	4	4	4	4	2
Flexibility	3	4	3	5	4	3	3	2
Environmental Responsibility	2	4	4	5	5	4	2	1
Rank	6	3	5	1	4	2	7	8

5.8 Conclusions

1. The results of the energy screening, based solely on costs, as shown in Table 13, do not produce a clear winner for the alternatives reviewed.

2. Based on this screening analysis and the provided price of fuel, the production of electricity does not greatly improve the community energy thermal price at an electrical price of \$150 / MWh_e.

3. If natural gas is available, it would be a good means of providing alternative energy capacity to a CES that could reduce the community's greenhouse gas emissions. At \$15 / GJ it would be a cheaper fuel alternative than fuel oil at \$26 / GJ (\$1/Litre).

4. The results indicate that the alternatives using oil fired reciprocating engines (Alternatives 7 & 8) do not produce viable alternatives at a fuel cost of \$1/Litre and an electricity price of \$150/MWh_e. When the price of electricity is increased to \$200/MWh_e Alternatives 7 & 8 (see Table 14) become more viable alternatives but are still less attractive than other alternatives.

5. The Biomass with ORC options (Alternatives 4 & 5) assume that the electrical generation is small enough that the electrical grid can absorb the additional electricity generation and Community heat can be supplied year-round. The cogeneration options (Alternatives 6, 7 & 8) assume that these units only run when electrical demand is high enough to warrant running the units. This screening assumes a run-time of 4,890 hours; however this may not reflect actual electrical demand and could affect the annualized cost of thermal energy.

6. Woodchip biomass or reciprocating engine cogeneration using natural gas produce similar prices of thermal energy and GHG reductions.

7. Woodchip biomass at $150 / tonne (Alternative 2) is an attractive, locally supplied option for the community. Adding ORC to this option (Alternative 4) has a significant positive impact on GHG reductions but has a marginal impact on thermal energy cost if electricity sales are at $150/MWh$_e$. In order to make ORC electrical production more viable a higher price of electricity is required. Increasing the electricity sale price from $150 to $200 / MWh$_e$ lowered the thermal cost of production for this solution from $99 to $90 / MWh$_{th}$. This could justify the increased capital cost associated with adding electrical production.

8. Wood pellets are a much better solution than the existing fuel oil alternatives when it comes to sustainability and GHG emissions but their high cost ($296 / tonne) compared to wood chips makes them a less viable alternative.

9. The screening analysis assumes a relatively high capital cost ($2,500 / kW$_e$) for the reciprocating engine capacity of 6 MW$_e$ for Alternative #6. If Yukon Energy develops a much larger electrical generation energy centre (>than 24 MW$_e$) than the capital cost could come down significantly and thus potentially reduce the cost of thermal energy to the CES.

5.9 Recommendations

The LNG alternatives (Alternatives 1 & 6) are dependent on factors outside the scope of this study. If it makes economic sense to bring LNG into the community to generate power, then it could be used as a fuel source for a CES that could be competitive with wood waste. The amount of power that would be optimally produced (thermal load following) using wood waste for a CES would not produce sufficient electricity to make a significant impact in the Yukon Energy projected electrical shortfall.

If one alternative is to be pursued for the CES, FVB recommends the effort be spent on a biomass based system with ORC (Alternative 4). Our reasoning is that work is being completed by others to solve the projected electrical shortfall using LNG and that if this option develops it will benefit a CES. We recommend this scope of work focus on a biomass alternative which could produce thermal energy at a competitive price to waste heat from reciprocating engine cogeneration.

5.10 Client Preferred Energy Source Selection

When presented with the eight alternative energy supply options for the baseload thermal energy supply, the steering committee requested that both Alternative 4 (biomass based system with ORC) and Alternative 6 (LNG cogeneration) be pursued.

Business Plan

The following section contains these subsections:

6 Community Energy System Design Plan

7 Capital Costs

8 System Operation & Maintenance Costs

9 Building Business-As-Usual Costs

10 Business Case Results

11 Marketing Plan

12 Risk Management

6 Community Energy System Design Plan

Community Energy Systems (CES) supply heat to multiple buildings from central sources. One of the advantages of CES is that it enables consumers to access alternative energy sources, which may be produced locally and subject to lower, more stable cost structures. Such sources include LNG fuelled reciprocating engine cogeneration and combustion of wood waste (biomass). The Whitehorse CES envisaged considers both of these technologies. As such, it would become a major infrastructure asset for the community.

A CES can be subdivided into three main components:

- Energy Centers (EC) that produce thermal energy for the system
- Distribution Piping System (DPS) that transport thermal energy in the form of hot water from the Energy Centres to the connecting buildings
- Energy Transfer Stations (ETS) that transfer the thermal energy from the DPS via heat exchangers for use in the customer building heating systems

6.1 Loads and Energy

Scenario #11 (see section 4 for description), includes the institutional and health care buildings along Hospital Road, some of the schools and residential units in Riverdale along Lewes Boulevard and Nisutlin Drive, as well as select buildings in the downtown core between 1st and 4th Avenues.

Target buildings were selected based on the amount of energy that could be displaced (building size), whether they currently utilize a hydronic based heating systems, if they have plans to replace current boilers, or if they are a future building currently in the planning or design process. Only buildings with a demand of greater than 100 kW were selected, with the following key buildings considered to be included in the proposed system:

- Whitehorse General Hospital
- Thomson Centre
- Education Building
- Yukon Territory Government Administration Building
- City Hall / Fire Hall
- High Country Inn and Convention Centre
- Yukon Energy Office
- Yukon Energy Hydro Generating Facility
- Yukon Justice Building
- Whitehorse Elementary School
- Elijah Smith Building
- Closeleigh Manor

Of the 43 identified buildings, 56% are government buildings and 84% of government buildings were assumed to connect to the proposed system.

For the purposes of the business plan, the CES was sized to meet the space heating and domestic hot water loads for the proposed connected buildings. Table 19 summarizes the load and energy assumption carried forward.

Table 19 - Summary of Diversified Load Assumptions

	Total Peak
Diversified Peak [MW]	14.6
Annual Energy [MWh]	41,100

6.2 Energy Transfer Stations

The Energy Transfer Station (ETS) is the interface between the CES and the building heating systems. An ETS can be provided for each building or alternatively provided for a group of buildings, typically where common ownership is in place, e.g. a lot or parcel with multiple buildings.

The energy meter on each ETS continuously meters the building thermal load. The energy meter is made up of a flow meter, two temperature sensors (supply and return) and an energy calculator. This equipment has the ability to measure the 15 minute peak heating demand of the building as well as the annual energy consumption over the year.

The selected meters could be connected to the controller for remote readout capability from the energy centre control system. FVB would specify meters that meet existing Canadian (CSA C900) and international (OIML R75 and EN1434) standards for thermal energy metering.

6.2.1 Building Connections

The ETS for the customers will be designed so that each building can be “indirectly” connected to the main distribution system. Indirect connection is the typical approach for DH, and means that each building’s internal heating and domestic hot water systems (secondary side) are isolated from the CES distribution system (primary side) by means of plate heat exchangers.

6.2.2 Design

The basic ETS would consist of the isolating valves, heat exchanger, actuated control valves, a digital controller, and an energy meter. The controller is used to sense the heat load demanded by the building and satisfies the heating demand by modulating the two-way control valves located on the primary side of the ETS.

The CES will supply up to 117°C (243°F) to each building ETS and return 77°C (171°F) hot water during peak periods at an expected maximum operating pressure of 1,600 kPa (~232 psig). The building’s internal heating system would draw heat from the ETS and supply water to its internal heating systems at a temperature of 70-80°C (160-180°F) and returning a blended maximum of 60°C (140°F) during peak operating conditions.

The expected temperatures are a reality of the heating system designs of the buildings served and existing building systems cannot be changed without major retrofit. Where CES can be applied to solely new buildings, and where these buildings are designed to accept lower temperatures, then the CES can lower its overall supply and return temperatures.

It is important to note that these temperatures are estimates and targets only. The system will be designed to be capable of operating at a supply temperature of 117°C, but may never need to operate at that level. Similarly, the summer operating temperatures are only estimates.

The temperatures of the district heating distribution system (primary side) will follow a setback schedule (or curve) based on the outdoor ambient temperature. The assumed CES supply and return temperatures are as noted in the table below:

Table 22 - CES Supply and Return Temperatures

Heating	Outside Air Temperature	Supply (°C)	Return (°C)
Peak Winter	< -18 °C	117	75
Winter	0 to -18 °C	90 - 117	70 - 75
Shoulder and Summer	> 0 °C	80	60

At these temperatures the CES has the capability to satisfy short-duration peak demands resulting in providing 100% of the energy needs of the building - this minimizes the need for additional equipment at the customer buildings.

The minimum heating supply temperature is dependent on the need for domestic hot water heating, which requires sufficient temperature to ensure public safety is maintained and a reasonable size of heat transfer area is provided. This is particularly the case where storage is provided, but also applies to instantaneous systems.

Actual setback schedules and operating temperatures will be determined and updated as the system enters operation and grows. As more new buildings (that require lower temperatures) are added, system temperatures should evolve.

6.2.3 Building Conversion Requirements

Existing buildings will typically require some modifications to connect to the CES. This was investigated where possible during site visits. Generally, only minor modifications are required to the existing buildings considered in this study. Costs for these modifications are included in the ETS cost estimate.

It is assumed that future buildings would be constructed for compatibility with district heating, and hence there would be no conversion requirements. Coordination with building developers will be essential during the design and implementation of the project.

6.3 Distribution Piping System

The distribution network is the physical link between energy sinks (customers) and sources (plants). The system proposed would consist of a below ground direct buried hot water distribution network with supply and return piping in a closed circuit (2-pipe system).

FVB has prepared a preliminary distribution piping concept including: routing, sizing, and material selection to provide community heating services to the targeted buildings.

6.3.1 Distribution Network Pipe Routing & Sizing

The pipe sizing for the selected route has been governed by the following four key factors:

- Supply and return temperature differentials, referred to as ΔT (delta T),
- Maximum allowable fluid velocity,
- Distribution network pressure at the design load conditions, and;
- Differential pressure requirements to service the most remote customer.

Distribution pipe sizes are based on ΔT of 40°C (72°F) and an allowable pressure drop of 175 Pascals per meter of pipe.

An approximate layout for the distribution system has been developed (Figure 8 below).

Figure 8 - Proposed Distribution Piping System Layout

The trunk lines are generally along major road and utility right-of-ways to reduce reclamation costs and damage to the ecosystem. The main lines follow Hospital Road, Lewes Boulevard, Nisutlin Drive, Robert Service Way, 2nd Avenue, Steele Street and 4th Avenue. Branch lines typically follow the shortest path to the building.

Table 20 - Distribution System Facts

	Full Build-out
Total DPS Length	8,700 tm [2]
Average pipe size	138 mm (5.45 inch)
Mainline sizes	100 - 200 mm (4 - 8 inch) [3]
Branch sizes	50 - 100 mm (2 - 4 inch)

6.3.2 Installation

The installation of the distribution system is assumed to be by excavated trench methods, with supply and return pipes in a “side by side” configuration. Generally, FVB has assumed an average depth of bury to the top of the pipes of approximately 1,200 mm cover. Actual depth of bury may vary depending on city burial depth requirements and the location of other utility services.

It is assumed that a communication conduit will be installed along with the distribution piping to allow for communication between each building ETS and energy centre controls. If desired, the City could install an additional conduit for its own internal use, or if a fibre optic network is planned then this could replace the need for new conduit/wiring. There are other options for communication with ETS, including internet-based and wireless (line of site). For the purposes of the capital cost estimates, a single communication conduit is assumed to be installed as it is the lowest cost option and provides full functionality required by the CES.

6.3.3 Distribution Piping Material

With a higher temperature system, insulated piping is required for the distribution network.

From a technical point of view, considering the size and capacity of the proposed CES distribution system, an all-welded steel piping system is recommended. The piping material can accommodate the required working temperatures, pressures and flow velocities and provides a watertight solution. Guarantees of uninterrupted service can be provided to potential customers with greater confidence than with other materials (e.g. mechanical jointed systems like PEX or ductile iron).

[2] Trench meters: pipe length is double the trench distance.

[3] Pipe sizes are nominal pipe diameters of the steel carrier pipe.

Medium Temperature Hot Water System, European st37.0, DIN 2458 (EN253 Standard) thin walled steel pipe, insulated with rigid polyurethane foam, with a high density polyethylene outer jacket and a built in leak detection system is recommended, and has been used as the basis for costs in this study.

Once the project moves forward to the execution stage, project specification documents should be developed such that more than one manufacturer's piping system may be considered.

6.4 Energy Centres

Three thermal energy centres are proposed for this project for hot water production. In time, each of the areas served by their respective energy centres would become interconnected to provide security of energy supply.

6.4.1 P1 Steam Conversion Energy Centre

The first energy centre, P1, would be established as an addition to the existing fuel oil hospital boiler energy centre. This energy centre is key to the initial development of community heating in Whitehorse. P1 would initially serve the immediate area around the hospital, and then transition to a back-up energy centre role as the overall system continues to develop.

Hot water will be primarily produced by utilizing spare steam boiler capacity that exists in the hospital steam boiler system. The surplus steam would be utilized in a new steam to hot water converter station to produce the required hot water for distribution to the community heating loads.

Based on information gathered from site visits, there is one spare low pressure steam boiler providing an estimated 4 MW_{th} of installed spare capacity located at the Whitehorse General Hospital. Use of this boiler in the CES would offer the following advantages:

- Limited additional capital; uses existing equipment within an existing building
- Limited additional costs for operation
- Allows for a delay of capital expenditure until later stages of phasing
- Moves the heat source closer to the largest loads

The fuel oil boilers are already in place and could provide capacity to the early stages of the system. At full build-out of the system, it would provide <1% of the heating energy required. The unit is only required during the coldest periods of winter, and it is estimated to run less than 100 hours of the year when the system is fully developed.

6.4.2 P2 Alternative Energy Centre

The second energy centre, P2, would be established approximately 600 meters south of the current Yukon Energy facilities to serve as the main energy producing facility for the proposed community system. The P2 energy centre would be operated continuously in a baseload operating role, using the proposed alternative energy supply concept.

This location has the following benefits:

- Minimizes impacts from energy centre emissions
- Reduces fuel delivery and fuel storage considerations
- Provides potential operational synergies with Yukon Energy operations
- Electrical infrastructure for cogeneration options are already in place
- The energy centre building will not have the same aesthetic requirements as a building in the downtown core

This study examines two energy concepts for P2.

6.4.2.1 P2 Biomass with ORC & Fuel Oil Peaking Boilers

The biomass concept considers a biomass based combined heat and power (CHP) via an organic Rankine cycle system with fuel oil peaking boilers.

In the ORC system, the biomass boiler produces hot oil that is exchanged with an organic fluid. The fluid is vapourized, and then expands across a turbine that generates electricity. The fluid then transfers heat with the return water from the CES which condenses and cools the organic fluid. In this process, the ORC produces 6.0 MW_{th} of recoverable heat, and 1.2 MW_e of electricity generation.

The biomass concepts could develop a local biomass industry utilizing harvest managed forests dedicated to the system, or wood from local burn sites. The fuel is assumed to be chipped and processed off-site to boiler “spec” grade and delivered in truck trailers to the energy centre site. The trucks would dump the fuel into a “live” storage container. The live fuel storage would be covered and attached to the main energy centre and fuel is automatically fed to the boilers as needed. Sufficient storage capacity is provided to meet a three-day peak burn rate (winter long weekend).

Flue gas exits via a stack that incorporates emissions cleanup equipment to reduce stack emissions of particulate matter to required limits.

Bottom ash and fly ash will be automatically collected into an ashbin. Ash is anticipated to be less than 3% by weight for wood chips and 1% for pellet fuel - needs to be confirmed once fuel source is chosen. Biomass ash has many good qualities and may be used for value added purposes, however specific approvals are required.

This facility would also house two - 4.0 MW_{th} non-condensing fire tube boilers. The boiler is designed with dual-fuel capability, and is able to use both fuel oil and natural gas with minor modifications. The system is assumed to be equipped with on-site fuel storage to maintain a full load on both boilers for 24 hours. The boilers are estimated to achieve a minimum of 80% seasonal conversion efficiency.

The business case reviewed three configurations as noted below:

- Two biomass combustors with ORC system
- Single biomass combustor with ORC system
- Single biomass combustor without the ORC system

These configurations represent means of capital cost reductions, but come with some operating limitations.

6.4.2.2 P2 LNG Cogeneration & LNG Peaking Boilers

The LNG concept proposes an LNG based combined heat and power (CHP) using reciprocating engines with waste heat recovery systems. Two cogeneration engines would each produce 3.0 MW_{th} of recoverable heat, and 3.3 MW_e of electricity generation. Additional peaking boilers are LNG fuelled.

Waste heat is assumed to be recovered from the LNG engines from:

- 1st stage mixture intercooler heat exchange
- Lube oil heat exchange
- Engine jacket water heat exchange
- Exhaust gas heat exchange

It is assumed that the LNG cogeneration units are electrical load following, and that as electricity is required in the winter months, this facility would create both heat and power for approximately 4,890 hours from October to April. These engines will run at full electrical output to maximize electricity generation.

The exhaust gas stream has the ability to bypass the heat recovery boiler if system heat is not required. There is also a 2nd stage intercooler heat exchange that uses low grade heat to vapourize the LNG fuel for the engines.

The P2 LNG peaking boilers provide peak capacity as required, as well as baseload heat during those times when the cogeneration units are not running. The energy centre has two - 4.0 MW_{th} non-condensing water tube boilers. The boiler is designed with dual-fuel capability, and is able to use both fuel oil and natural gas with minor modifications.

The boilers are estimated to achieve 80% seasonal conversion efficiency. The boiler output will experience an additional 1.5% of energy loss as the LNG is vapourized and pre-heated.

6.4.2.3 P3 Downtown Back-up Energy Centre

The final energy centre, P3, would be installed in the downtown and would serve as a back-up energy centre. Adding the energy centre in the downtown core will delay capital expenditure and significantly improve the reliability of the system. Consideration should be give to using existing floor space and/or boiler capacity from one of the larger government buildings to reduce capital and operating costs.

The third energy centre location is estimated to be located within the downtown core and nearest the highest concentrations of building loads. The proposed energy centre would have a total installed capacity of 4.0 MW_{th}. This capacity is installed as a back-up energy centre with all heating demand designed to be provided by the other two energy centres. This configuration has the following benefits:

- Provides the overall system with a high degree of reliability
- Located close to largest concentration of customers.
- Defers some energy centre costs to the future.

6.5 Phasing

All attempts have been made to provide redundancy in thermal capacity, while delaying energy centre development until the capacity is required. This allows for capital flow from the customer base to help offset capital expenditures.

6.5.1 Pipe Routing and Customer Base

The pipe work is divided into five distinct phases, based on the amount of trench meters that can be reasonably installed within a construction season. The following figure shows the overall concept for pipeline phasing. Additional details can be found within the appendices of the Design Basis Document found in Appendix H.

Figure 9 - DPS System Phasing and Overall Layout

In the first phase, the piping would extend from the hospital energy centre along Hospital Road and Lewes Boulevard up to the Selkirk Elementary School.

Phase 2 piping is proposed to extend down Lewes Boulevard, and down Nisutlin Drive. This routing includes crossing the Yukon River at the existing footbridge near the generating station and crossing Robert Service Way to connect to the proposed energy centre P2 location.

With the base capacity at energy centre P2 established, phase 3 connects the CES to the energy dense downtown zone, supplying thermal energy to buildings located along First and Second Avenue. Phase 3 includes crossing the Yukon River using the underside of the Yukon River Bridge.

Phase 4 continues developing the downtown core with lines following Steele Street and down Fourth Avenue. This phase includes connecting the distribution piping system to the proposed downtown energy centre P3.

The final phase is proposed to connect the remainder of the Riverdale customers.

Final routing and phasing of the distribution piping would be established during the design phase of the project. The final design would need to take into account energy centre location, actual customer buildings that commit to the CES, timing of infrastructure improvements, and coinciding major development or heating system replacements. With the LNG cogeneration concept timing would depend on Yukon Energy's schedule for increased electrical generation. Coordination of the routing with the City of Whitehorse must also be completed before finalizing the piping network design.

6.5.2 Biomass Concept

Table 21 - Biomass Concept Energy Centre Phasing

Biomass Concept	Capacity Added
Phase 1	4.0 MW_{th} of Steam Conversion Capacity at P1
Phase 2	One - 3.5 MW_{th} Biomass Combustor at P2 One - 4.0 MW_{th} Fuel Oil Peaking Boiler at P2
Phase 3	One - 3.5 MW_{th} Biomass Combustor at P2 One - 4.0 MW_{th} Fuel Oil Peaking Boiler at P2
Phase 4	One - 1.2 MW_{e} ORC Unit at P2 One - 4.0 MW_{th} Fuel Oil Boiler at P3
Phase 5	-

The phasing indicated is based on the anticipated order in which each of the energy centres would be established. The proposed steam conversion facility adjacent to the hospital, P1, is expected to be the first to be constructed. This will allow the CES to get started and operating as soon as possible.

For phase 2, one biomass combustor and one fuel oil peaking boiler is developed at energy centre P2. As load increases, the second energy centre P2, would be established to serve as the main heat producing facility for the CES. The P2 energy centre would be operated continuously in a baseload operating role.

In phase 3, as energy demand increases on the system, the second biomass combustor and fuel oil peaking boiler is installed. Splitting the P2 development into two phases allows the system to utilize a high percentage of low fuel cost biomass-based thermal capacity in the early stages. The fuel oil boilers are installed to provide system reliability and peaking capacity.

In phase 4, there is sufficient energy demand to justify adding the ORC unit to produce electricity. Also in this phase, the final plant, P3, would be installed downtown.

6.5.3 LNG Concept

Table 22 - LNG Concept Energy Centre Phasing

LNG Concept	Capacity Added
Phase 1	4.0 MW_{th} of Steam Conversion Capacity at P1
Phase 2	Two - 3.0 MW_{th} LNG Cogeneration Engines at P2
Phase 3	One - 4.0 MW_{th} LNG Boiler at P2
Phase 4	One - 4.0 MW_{th} LNG Boiler at P2 One - 4.0 MW_{th} Fuel Oil Boiler at P3
Phase 5	-

As with the biomass system, the first energy centre developed is the steam conversion facility located at the hospital.

In phase 2, both LNG cogeneration engines are installed at P2 energy centre. These units have full heat rejection capability and are able to operate at full capacity to maximize the electricity generation, as required by the Yukon electrical infrastructure.

In phase 3, as energy demand increases on the system, the 1st LNG peaking boiler is installed at energy centre P2.

In phase 4, the 2nd LNG peaking boiler is installed and energy centre P2. Also in this phase, the final plant, P3, would be installed downtown.

7 Capital Costs

The concept capital cost has been based on the following description with additional details provided in the attached Design Basis Document (see Appendix H).

7.1 Energy Centre Capital Cost Estimate Summary

FVB has prepared the following phasing and cost estimates based on the concept described above and including the cost assumptions noted in Appendix D.

7.1.1 Biomass Concept

The initial phase connects the CES to the existing capacity at the hospital.

Next, energy centre 2 begins development with the building and one of the two 4 MW_{th} fuel oil boilers and one of the two 3.5 MW_{th} biomass combustors. In phase 3, as load on the system increases the additional 4 MW_{th} fuel oil peaking boiler and additional 3.5 MW_{th} biomass combustor is installed.

In phase 4, there is enough customer load to begin installation and operation of the ORC unit. Of note, when the unit is installed, the heat capacity of the biomass system is decreased as the ORC unit requires some of the biomass capacity to produce electricity. This phase also develops the 4.0 MW_{th} fuel oil back-up boiler at the Energy Centre #3 site to provide energy security for the downtown customers. Details are provided in the following table.

Table 23 - Biomass Design Basis Phased Development

ORC Phased Operation Biomass Boiler with ORC Cycle	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Contract Load	4.80 MW	6.10 MW	10.20 MW	14.70 MW	17.20 MW
Diversified Load	4.08 MW	5.19 MW	8.67 MW	12.50 MW	14.62 MW
Total Capacity	4.0 MW	11.5 MW	19.0 MW	22.0 MW	22.0 MW
Total "N-1" Capacity		7.5 MW	15.0 MW	18.0 MW	18.0 MW
Redundancy		144.6%	173.0%	144.1%	123.1%

The “Biomass” Energy Centre capital cost is based on a biomass combustion and organic Rankine cycle system that can meet required emission and performance targets, as per direction from the previous screening analysis. Budget quotes were received from each of a combustion supplier and an ORC supplier.

Details of the energy centre capital cost estimates are found in Appendix D.

Table 24 - Biomass Design Basis Capital Cost Estimate

ORC Phased Operation Biomass Concept	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Capital Costs					
P1 Hospital Connection	$1,171,000				
P2 Fuel Oil Boiler Energy centre		$4,974,000	$579,000		
P2 Biomass Energy centre		$9,855,000	$4,188,000		
P2 ORC				$4,705,000	
P3 Fuel Oil Boiler Energy centre				$2,306,000	
Total Energy Centre Capital	$1,171,000	$14,829,000	$4,767,000	$7,011,000	$0

In the final phase, there is no additional capital required for the energy centres.

This concept is based on two (2) 3.5 MW_{th} biomass combustors. Smaller units are more flexible in low load seasons due the ability to shut off one of the units when the turndown limits the ability to run both. This allows for a biomass system to be implemented during earlier phases (phases 2 and 3) when load on the system is lower. A single 7.0 MW_{th} combustor wouldn't have enough load to operate until phase 3.

Though switching to a single combustor saves an overall capital cost of approximately $3 million, the two (2) biomass combustor system results in a more favorable business model.

7.1.2 LNG Concept

Similar to the biomass concept, the initial phase connects a CES to the hospital. In phase 1, the total customers load is greater than the installed capacity. This phase assumes that the hospital is self-sufficient and will not become a community energy customer until phase 2.

Energy Centre #2 begins development in phase 2 with the building both 3.05 MW_{th} LNG cogeneration units. These units are assumed to be electrical load following, so although the heat cannot be fully utilized by the CES at this time, the electricity revenue generated can help offset capital costs incurred.

In phase 3, as load on the system increases one of the two 4 MW_{th} LNG peaking boilers is installed at the Energy Centre #2 site.

Phase 4 develops the other 4.0 MW_{th} LNG back-up boiler at the Energy Centre #2 site, as well as the Energy Centre #3 site with 4.0 MW_{th} fuel oil back-up boiler. Details are provided in the following table.

Table 25 - LNG Design Basis Phased Development

LNG Phased Operation LNG CHP Engine	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Contract Load	4.80 MW	6.10 MW	10.20 MW	14.70 MW	17.20 MW
Diversified Load	4.08 MW	5.19 MW	8.67 MW	12.50 MW	14.62 MW
Total Capacity	4.0 MW	10.1 MW	14.1 MW	22.1 MW	22.1 MW
Total "N-1" Capacity		6.1 MW	10.1 MW	18.1 MW	18.1 MW
Redundancy		117.6%	116.5%	144.9%	123.8%

The "LNG" Energy Centre capital cost is based on a LNG fuelled CHP engine system that can meet required emission and performance targets, as per direction from the previous screening analysis. Budget quotes were received from an engine supplier. Details of the energy centre capital cost estimates are found in Appendix D.

Table 26 - LNG Design Basis Capital Cost Estimate

LNG Phased Operation LNG Concept	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Capital Costs					
P1 Hospital Connection	$1,171,000				
P2 LNG Boiler Units			$4,655,000	$579,000	
P2 Cogen Units		$15,278,000			
P3 Fuel Oil Boiler Energy Centre				$2,306,000	
Total Energy centre Capital	$1,171,000	$15,278,000	$4,655,000	$2,885,000	$0

In the final phase, there is no additional capital required for the energy centres.

7.2 Distribution Piping System Capital Cost Estimate Summary

FVB has prepared the following phasing and cost estimates based on the concept described above. Cost assumptions noted in Appendix D.

Table 27 - Distribution Piping System Capital Cost Estimate

DPS Capital	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Trench Meters	1,770 m	2,470 m	1,905 m	1,600 m	960 m
Average Pipe Size	138 mm	190 mm	135 mm	99 mm	80 mm
DPS Capital	$3,029,000	$5,450,000	$3,856,000	$2,445,000	$1,286,000

Included in Phase 2 is additional costing to cross the Robert Service Highway and the Yukon River via the existing footbridge. In phase 3, additional cost is associated with the pipeline crossing the river to downtown via the underside of the existing Yukon Bridge.

In total, 8,700 trench meters of distribution piping is proposed for the CES at a total cost of $16,066,000 excluding taxes. A more detailed DPS cost summary can be found in Appendix D.

7.3 Energy Transfer Station Capital Cost Estimate Summary

FVB has prepared the following phasing and cost estimates based on the concept described above. Cost assumptions provide for some building modifications. Further assumptions are detailed in Appendix D.

Table 28 - Energy Transfer Station Capital Cost Estimate

ETS Capital	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
# of ETS	6	4	12	13	8
Average ETS Size	1,008 kW	380 kW	406 kW	416 kW	369 kW
ETS Capital	$1,209,000	$638,000	$1,925,000	$2,118,000	$1,305,000

The concept incorporates a total of 43 energy transfer stations at a total cost of $7,193,800. These provide a total of 20,800 kW of heating to the connected customers. A more detailed ETS cost summary can be found in Appendix D.

7.4 Design Basis Capital Cost Estimate Summary

7.4.1 Biomass Concept Capital Cost Estimate

The total cost of the proposed biomass concept is summarized in the table below.

Table 29 - Biomass Concept Total Capital Cost Estimate

Biomass Concept Capital Cost	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Energy Centre Capital Cost	$1,171,000	$14,829,000	$4,767,000	$7,011,000	
DPS Capital Cost	$3,029,000	$5,450,000	$3,856,000	$2,445,000	$1,286,000
ETS Capital Cost	$1,209,000	$638,000	$1,925,000	$2,118,000	$1,305,000
Total Energy centre Capital	$5,409,000	$20,917,000	$10,548,000	$11,574,000	$2,591,000
					$51,039,000

The total capital cost for the energy centre, distribution piping and energy transfer stations for the biomass concept is $51,039,000, excluding taxes.

This concept is based on two (2) 3.5 MW_{th} biomass combustors. Smaller units are more flexible in low load seasons due the ability to shut off one of the units when the turndown limits the ability to run both. This allows for a biomass system to be implemented during earlier phases

(phases 2 and 3) when load on the system is lower. A single 7.0 MW_{th} combustor wouldn't have enough load to operate until phase 3.

Though switching to a single combustor saves an overall capital cost of approximately $3 million, the two (2) biomass combustor system results in a more flexible system.

7.4.2 LNG Concept Capital Cost Estimate

The total cost of the proposed LNG concept is summarized in the table below.

Table 30 - LNG Concept Total Capital Cost Estimate

LNG Concept Capital Cost	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Energy Centre Capital Cost	$1,171,000	$15,278,000	$4,655,000	$2,885,000	
DPS Capital Cost	$3,029,000	$5,450,000	$3,856,000	$2,445,000	$1,286,000
ETS Capital Cost	$1,209,000	$638,000	$1,925,000	$2,118,000	$1,305,000
Total Capital Cost	$5,409,000	$21,366,000	$10,436,000	$7,448,000	$2,591,000
					$47,250,000

The total capital cost for the energy centre, distribution piping and energy transfer stations for the biomass concept is $47,250,000, excluding taxes.

The key capital difference between the biomass and LNG concept is in Phase 4, where in the biomass concept the ORC system is purchased.

8 System Operation & Maintenance Costs

The concept O&M cost has been based on the following. Additional details of the Operation and Maintenance can be found in Appendix E.

8.1 General

- Fuel Oil Cost of $1.00 per Liter with a 38.91 MJ/L HHV
- Electricity blended purchase price of $145.70 per MWh
- Electricity sales price of $150 per MWh
- Blended water and sewer cost of $1.68 per m^3
- 80% HHV seasonal boiler efficiency for all fuel oil boilers
- 1 Chief operator and 1 additional operator for 1st phase
- 3 additional operators for other phases
- Since energy purchase costs have not been determined from the hospital for the Energy Centre #1 conversion, the fuel, operation and maintenance costs have been assumed for all energy centres. Once a purchase price is negotiated, actual costs for the Energy Centre #1 energy supply may increase. However, this only affects the first phase of the system build-out.
- Priority is given for heat recovery from electrical production equipment, as applicable. This is followed by thermal energy from the P-2 peaking boilers, then the P-1 hot water conversion system and, finally, the P-3 fuel oil back-up boilers.

8.2 Biomass Design Basis O&M Cost

- The electricity generation is assumed to be thermal load following
- Biomass feedstock assumed to be boiler ready at $150/green tonne (Morrison Hershfield, September 14, 2011)
- Higher heat value of 20.6 GJ/ green tonne (8,856 BTU/lb) and 25% moisture content
- Assumes ash disposal cost at $40/ton
- Biomass boiler is assumed to have a boiler seasonal efficiency of 73% HHV
- Organic Rankine Cycle unit is assumed to have an efficiency of 81% HHV

Table 31 - Biomass design basis O&M cost summary

Total Annual Costs	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Fuel Cost	$1,455,000	$913,000	$1,297,000	$2,279,000	$2,747,000
Electrical Consumption	$9,000	$122,000	$209,000	$299,000	$308,000
Electricity Sales	$0	$0	-$0	-$917,000	-$1,004,000
Makeup Water Cost	$5,000	$5,000	$8,000	$17,000	$19,000
Operating and Maintenance Cost	$23,000	$194,000	$264,000	$349,000	$362,000
Administration and Personnel Cost	$218,000	$673,000	$736,000	$817,000	$823,000
Total Annual Operating Cost	**$1,710,000**	**$1,907,000**	**$2,514,000**	**$2,844,000**	**$3,255,000**

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8.3 LNG Cogeneration Design Basis O&M Cost

- The LNG cogeneration units are assumed to be electrical load following, running for 4,890 hours of the year
- LNG cost of $15 per GJ with a 10.5 kWh/m^3 HHV
- LNG peaking boilers are assumed to have a boiler seasonal efficiency of 80% HHV
- LNG peaking boilers are assumed to utilize 1.5% of their heat to vapourize and pre-heat the LNG fuel.
- LNG cogeneration units are assumed to have an electrical efficiency of 45.2% LHV

Table 32 - LNG cogeneration design basis O&M cost summary

Total Annual Costs	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Fuel Cost	$1,455,000	$4,734,000	$4,699,000	$5,015,000	$5,285,000
Electrical Consumption	$8,000	$125,000	$108,000	$105,000	$101,000
Electricity Sales	$0	-$4,851,000	-$4,851,000	-$4,851,000	-$4,851,000
Makeup Water Cost	$4,000	$11,000	$12,000	$16,000	$17,000
Operating and Maintenance Cost	$23,000	$508,000	$625,000	$625,000	$636,000
Administration and Personnel Cost	$218,000	$677,000	$779,000	$779,000	$786,000
Total Annual Operating Cost	**$1,708,000**	**$1,204,000**	**$1,372,000**	**$1,689,000**	**$1,974,000**

8.4 Fuel Supply and Demand

This section studies the viability of the feedstock at full build-out. The following table is gathered from the biomass feedstock evaluation of Whitehorse (Morrison Hershfield, August 27, 2012).

Table 33 - Wood Chip Sources and Annual Supply

Source	Damage	Distance to Whitehorse	Tonnes of Available Wood Annually
Haines Junction	Spruce Beetle	180 km	45,455 ODT
Fox Lake Fire (1998)	Burn Site	90 km	24,440 ODT
Minto (1995)	Burn Site	260 km	75,508 ODT
Total Resource			**145,403 ODT**

As seen above, the Fox Lake fire site, located just outside the city can provide an estimated 24,440 ODT of wood chips annually. The combined resources can supply over 145,000 ODT annually.

Table 34 shows the estimated fuel consumption for the biomass concept.

Table 34 - Biomass Concept Annual Fuel Consumption

Biomass with ORC Concept	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Wood Chip Consumption (ODT)		3,400 ODT	5,600 ODT	9,200 ODT	10,100 ODT
Annual Fuel Oil Consumption	1,454,900 L	229,000 L	161,900 L	411,700 L	702,100 L

As shown, at full build-out the biomass with ORC concept has an estimated annual wood chip consumption of 10,100 ODT. This demand is approximately 41% of the total amount of wood chips that can be provided by the nearby Fox Lake fire site, or 7% of the total wood chip sources identified in the area. This value shows that there is a high fuel source flexibility and low risk with the available wood chip feedstock.

At full build-out, there is an estimated 700,000 Litres of fuel oil that is consumed annually.

The following table shows the estimated fuel consumption for the LNG concept.

Table 35 - LNG Concept Annual Fuel Consumption

LNG Concept	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Fuel Oil Consumption	1,455,000 L	445,000 L	4,000 L	0 L	1,000 L
Peaking Boiler(s) - LNG Consumption	0 m^3	0 m^3	716,000 m^3	1,281,000 m^3	1,755,000 m^3
Cogen Engine(s) - LNG Consumption	0 m^3	7,564,000 m^3	7,564,000 m^3	7,564,000 m^3	7,564,000 m^3

As shown, approximately 9.3 million cubic meters of LNG are required annually for this concept. There is also, approximately 1,000 L of fuel oil that is consumed annually at full build-out.

9 Building Business-As-Usual Costs

9.1 General

One of the most important elements in any successful Community Energy business is the revenue stream. The revenue stream is the product of the volume and the selling price of the hot water service being sold by the CES.

The value of the hot water is based on the building owners' cost to produce heating and domestic hot water with their proposed or existing equipment. This is referred to as the Business-As-Usual (BAU) heating costs or self-generation costs. These costs have been estimated based on various inputs from FVB's experience marketing community energy to building owners across North America.

9.2 BAU Cost Inclusions

The BAU costs have been developed for each building proposed for connection to the CES. These costs represent the value that would be displaced by connecting to the CES.

The following table summarizes the business as usual costs for seven key buildings. Specific cost assumptions can be found in Appendix F.

Table 36 - Summary of Annual BAU Costs for Seven Sample Buildings

BAU Cost Items	Building No. 1	Building No. 2	Building No. 3	Building No. 4	Building No. 5	Building No. 6	Building No. 7
Fuel	$62,500	$106,500	$150,800	$167,100	$1,010,200	$314,800	$99,700
Electricity	$300	$400	$500	$600	$8,100	$1,300	$300
Water, Chemicals, Sewer	$300	$500	$500	$600	$19,600	$1,300	$300
Boiler Insurance	$900	$1,300	$2,100	$2,500	$15,300	$5,500	$4,200
Equipment Maintenance	$4,700	$7,700	$12,500	$7,900	$41,200	$15,700	$7,500
Labour for Supervision	$9,800	$13,700	$9,800	$13,700	$39,000	$9,800	$23,400
Admin. & Mgmt	$2,000	$2,700	$2,000	$2,700	$7,800	$2,000	$4,700
Capital Replacement[4]	$9,600	$13,600	$22,600	$26,100	$162,700	$58,600	$44,200
Total Annual BAU Cost	**$90,100**	**$146,400**	**$200,800**	**$221,200**	**$1,303,900**	**$409,000**	**$184,300**
Total Annual BAU cost per MWh thermal	**$210**	**$195**	**$226**	**$212**	**$188**	**$185**	**$341**

[4] Annualized at 6.2% over 25 years

10 Business Case Results

10.1 Development of the Business Case

A financial model has been prepared to project the business case of the proposed CES. In order to compare various alternatives and sensitivities, cost based rates were developed that produce an 8.77% return on equity (ROE) required by Yukon Energy. Rates were developed for both the biomass concept (biomass based system with ORC) and LNG concept (LNG cogeneration). Three different biomass configurations were analyzed:

- 2 x 3.5 MW_{th} biomass boilers with an ORC turbine generator
- 7.0 MW_{th} biomass boiler with an ORC turbine generator
- 7.0 MW_{th} biomass boiler without an ORC turbine generator

Other than the biomass boiler size(s) and ORC configuration, all other aspects of the biomass concept are the same as previously discussed.

The table below compares the initial projected rate and the levelized rate for each of the four alternatives. The levelized energy rate is calculated as the present value of the total stream of revenues over 25 years divided by the present value of the total stream of energy delivered over 25 years.

Table 37 - Summary of Rates ($/MWh)

	Levelized Rate	Initial Rate
2 x 3.5 MW_{th} biomass with ORC	$197.14 /$MWh_{th}$	$157.54 /$MWh_{th}$
7 MW_{th} biomass with ORC	$215.16 /$MWh_{th}$	$171.94 /$MWh_{th}$
7 MW_{th} biomass without ORC	$220.17 /$MWh_{th}$	$175.94 /$MWh_{th}$
LNG Cogen Engines	$195.63 /$MWh_{th}$	$153.13 /$MWh_{th}$

The lowest rates and therefore the most competitive are provided by the LNG cogeneration concept. The full model outputs, including income statements, balance sheets and cash flow statements, are included in Appendix G. It is important to note that while the business case projects a reasonable ROE over the study period, the CES incurs cash losses in the first years of operation. These losses, while decreasing each year, would have to be funded from other sources. This amount would be required in addition to the capital costs previously estimated.

The following sections highlight the key assumptions and results of all business case models. Assumptions shown below are the same for all business cases unless specifically indicated otherwise.

10.1.1 General Assumptions

The business case has the following general assumptions:

- General Inflation - 2.0%
- Electricity and Natural Gas Inflation - 2.0%
- Life of assets - 25 years
- No taxes or land costs were assumed

10.1.2 Financing Assumptions

The business case has the following financing assumptions which were provided by Yukon Energy:

- 60% Debt
- Repayment term - 25 years
- Interest rate - 4%

10.1.3 Thermal Capacity & Commissioning

The connected customer heating capacity has been previously described. The total projected customer capacity is assumed to be connected in phases. Table 38 below shows the phased installed plant equipment capacity and the total customer contracted capacity. Each customer contract would have a capacity that is contracted to be available to that customer at any time. The diversified peak load is assumed to be 85% of the contracted capacity. The energy centre must contain enough installed capacity to meet the diversified peak load reliably. Table 39 shows the phase timing.

Table 38 - Connected Heating Capacity Assumptions

Phase	1	2	3	4	5	Total
Customer Heating Capacity	4,080 kW	1,110 kW	3,480 kW	3,830 kW	2,120 kW	14,620 kW
Contract Capacity	4,800 kW	1,300 kW	4,100 kW	4,500 kW	2,500 kW	17,200 kW

Table 39 - Phase Timing Assumptions

Phase	Construction Year	Commissioning Date
1	Year 2013	January 2014
2	Year 2015	January 2016
3	Year 2017	January 2018
4	Year 2019	January 2020
5	Year 2021	January 2022

10.1.4 Variable Cost Assumptions - Heating

The variable cost assumptions are based on the current tariffs in effect in the City of Whitehorse. The production efficiency assumptions are based on FVB's operating history experience. The resultant cost for production for each major variable cost is identified in Table 40 below. The costs are in 2012 dollars, and are escalated at 2% inflation rate.

Table 40 - Variable Cost Assumptions

Assumptions	Biomass Concept	LNG Concept
Purchased Steam ($/MWh)	$150/MWh	$150/MWh
Fuel oil ($/GJ)	$25.64/GJ	$25.64/GJ
Biomass ($/tonne[5])	$130/tonne	-
LNG ($/GJ)	-	$15.00/GJ
Electricity Tariff ($/kWh)	$0.146/kWh	$0.146/kWh
Electrical Sales Price ($/kWh)	$0.150/kWh	$0.150/kWh
Water & Sewer Tariff ($/1000 IG)	$7.64	$7.64
Chemicals Cost ($/MWh)	$0.0002/MWh	$0.0002/MWh
FO Boiler Seasonal Efficiency	80%	80%
Biomass Boiler Seasonal Efficiency	73%	-
LNG Boiler Efficiency	-	78.5%
Biomass Heating Value (MJ/kg)	20.60 MJ/kg	-
Electricity Usage (kWh/MWh thermal)	32.54 kWh	15.00 kWh
Water Usage (IG/MWh)	0.02 IG	0.02 IG

10.1.5 Fixed Cost Assumptions - Heating

Assumptions for fixed costs of heating production and distribution for each alternative are shown in Table 41 below. These assumptions are based on FVB's operating history experience.

Table 41 - Fixed Cost Assumptions

Assumptions	Biomass Concept	LNG Concept
Plant Labour ($)	$390,000	$390,000
Maintenance (% of capital cost)	0.50%	0.85%
Materials & Supplies (% of capital cost)	0.10%	0.25%
Insurance (% of capital cost)	0.35%	0.35%
Percentage of variable costs	3.5%	3.0%
Percentage of fixed costs	4.0%	2.5%

[5] Biomass cost: Dollars per metric green tonne, based on 25% moisture content.

10.2 Price Development and Analysis

While the model allows the user to build a cost based price that yields a desired return, this analysis may not have value if the cost based price is not tested against the avoided cost of self-generation. FVB has made an avoided cost analysis for existing buildings with a hydronic heating system in the proposed area.

The table below shows the rates in year 2014 (initial year of operation) with the return on equity (ROE) fixed at 8.77% compared to the estimated self generation costs for eight of the larger buildings in the proposed area. The calculation of self generation costs was summarized previously and discussed in detail in Appendix F.

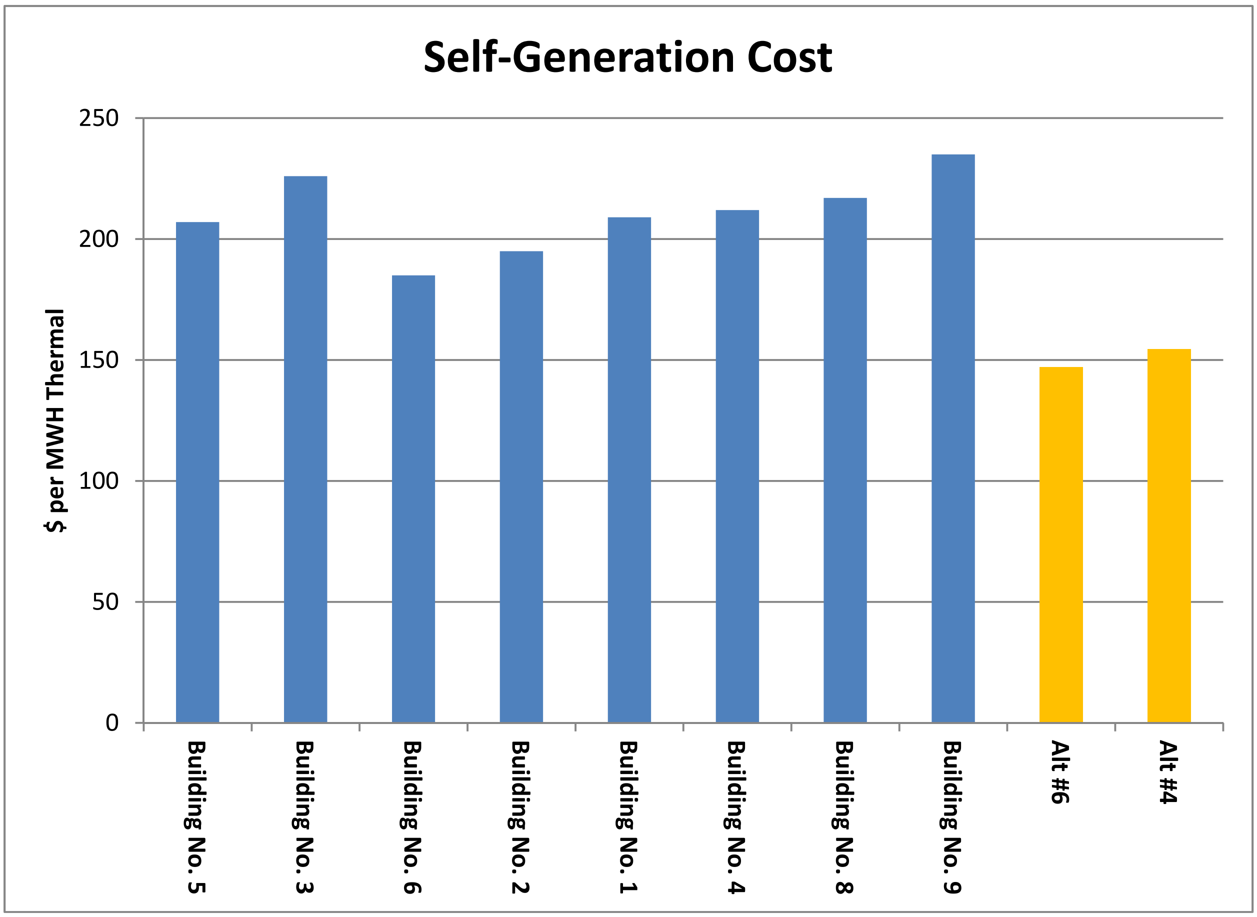

Figure 10 - BAU Avoided Cost vs. Blended CE Rate (2014 $/MWh)

The CES is competitive with the existing hydronic buildings for both the biomass concept and LNG concept.

10.3 Financial Results

The full business case outputs, including Income Statements and Balance Sheets, are included in the Appendix G. The financial results are based on achieving a competitive rate with the BAU scenario and providing the expected return to Yukon Energy.

10.3.1 Sensitivities

The following sensitivities have been analyzed for the biomass and LNG concept.

- +25% -10% in total capital costs
- +25% -15% in biomass and LNG costs
- +$0.03 -$0.03 per kWh electric sale price
- + 10 years for full build out of CES

The impact of higher or lower capital costs on the ROE is shown in Table 42 below.

Table 42 - ROE Sensitivity to Capital Cost

Alternative	Base case	+ 25% Capital	-10% Capital
Biomass Concept - Two x 3.5 MW_{th} with ORC	8.77%	5.07%	10.57%
Biomass Concept - 7MW_{th} with ORC	8.77%	5.61%	10.27%
Biomass Concept- 7MW_{th} without ORC	8.77%	5.73%	10.22%
LNG Concept - Two x 3.0_{th} MW Cogen	8.77%	4.95%	10.62%

It can be seen that the ROE is sensitive to changes in capital costs.

The impact of higher or lower fuel costs on the ROE is shown in Table 43 below.

Table 43 - ROE Sensitivity to Fuel Cost

Alternative	Base case	+ 25% Fuel Cost	-10% Fuel Cost
Biomass Concept - Two x 3.5 MW_{th} with ORC	8.77%	7.26%	9.64%
Biomass Concept - 7MW_{th} with ORC	8.77%	7.75%	9.35%
Biomass Concept- 7MW_{th} without ORC	8.77%	7.86%	9.29%
LNG Concept - Two x 3.0_{th} MW Cogen	8.77%	1.52%	12.71%

It can be seen that the biomass concept ROE's are mildly sensitive to biomass fuel price changes. However, the LNG concept is highly sensitive to LNG price changes to the point that the plus 25% case drives the project to an unacceptable low ROE.

The impact of higher or lower electric sale price on the ROE is shown in Table 44.

Table 44 - ROE Sensitivity to Electric Sales Price

Alternative	Base case	+ 0.03/kWh	-$0.03/kWh
Biomass Concept - Two x 3.5 MW_{th} with ORC	8.77%	9.42%	8.09%
Biomass Concept - $7MW_{th}$ with ORC	8.77%	9.38%	8.14%
Biomass Concept- $7MW_{th}$ without ORC	8.77%	8.77%	8.77%
LNG Concept - Two x 3.0_{th} MW Cogen	8.77%	13.49%	3.91%

It can be seen that biomass with ORC cases are mildly sensitive to the electric sales price. However, the LNG concept is very sensitive to electric sales price changes. The sensitivity presented is obviously related to the amount of electric production associated with each case.

The impact on Return on Investment (ROI) of doubling the length of time to complete the full build-out of the CES is shown in Table 45 below. ROI in chosen for comparison because ROE has multiple solutions due to the positive and negative variations in cash flow over the longer period.

Table 45 - ROI Sensitivity to Longer Build out of the CES

Alternative	Base case	20 year Build-out
Biomass Concept - Two x 3.5 MW_{th} with ORC	6.73%	6.83%
Biomass Concept - $7MW_{th}$ with ORC	6.90%	7.79%
Biomass Concept- $7MW_{th}$ without ORC	6.96%	7.09%
LNG Concept - Two x 3.0_{th} MW Cogen	6.78%	11.22%

It can be seen that the biomass concept options are mildly sensitive to the longer build-out period. This is because the capital required to serve loads is also invested over a longer period. However, LNG concept is more sensitive to the longer build-out period. The ROI improves due to the fact that this is a primarily a generation project and the less profitable CES investments come later.

11 Marketing Plan

11.1 Target Market Area

One of the first steps in developing a successful CES is to identify potential customers. Some conditions that are representative of a good potential community energy candidate are:

- Larger sized buildings, for which a significant amount of energy would be displaced by a CES, such as hospitals, large condominiums, office buildings, etc.
- Buildings that already utilize hydronic heating systems.
- Buildings that are planning to replace boilers or heating sources.
- Future buildings in the planning or design stage.

The larger buildings were targeted and their heating requirements quantified as discussed previously.

As previously discussed the area found to be the most feasible for the development of a new CES in Whitehorse combines Zone #1 - Lewes Boulevard, Zone #2 - Hospital Road and Zone #3 - Downtown Core. These zones have a total connected load of 17.2 MW_{th} and require 41,100 MWh of heating energy. This area represents the largest potential for connecting loads.

This scenario was further refined to reflect a more accurate business case. Of the 43 identified buildings, 44% of non-government buildings and 84% of government buildings were targeted to connect to the system.

11.2 Target Buildings

The key loads in this area have been identified as the Whitehorse General Hospital, Thompson Centre, Education Building, Yukon Territory Government Administration Building, City Hall/Fire Hall, Elijah Smith Building, Yukon Justice Building, Whitehorse Elementary School, High Country Inn and Convention Centre, Closeleigh Manor, Yukon Energy Office and Yukon Energy Hydro Generating Facility.

11.3 Target Buildings BAU Cost

BAU cost development and importance has been previously described in Section 9. BAU costs were estimated for seven of the key loads. The summary can be found in Table 36 .

11.4 CES Rate Development

In the previous section, financial models were created for several business cases. In these models two part rate structures were developed. One part of the rate structure is designed to recover variable costs of the CES and the other part recovers the fixed cost component. The rates developed were designed to provide Yukon Energy its required return on equity.

The table below presents the initial rate structure for the business case that produced the lowest levelized rate.

Table 46 - CES Lowest Levelized Rate

Business Case	Capacity Rate	Energy Rate	Average Rate
LNG Cogen Engines	$18.77/kW/month	$0.07/kWh	$153/MWh

11.5 CES Rate vs. BAU Cost Comparison

As previously shown in the preceding section, the comparison of the initial average rate to BAU costs for seven of the targeted buildings is very favorable. The chart demonstrating that comparison is found in Figure 10.

11.6 Marketing Plan of Action

Step 1 of the marketing plan of action would begin with the acceptance of this report and its conclusions by Yukon Energy. Term sheets for seven of the targeted customers have been created by FVB for marketing use. These term sheets explain the CES to customers, how the business as usual costs is estimated and compares the BAU costs to the offered CES rates.

Meetings would be held with each potential customer to present the term sheet and receive any comments. Assuming a positive response, a draft MOU has been created and would be presented for negotiation and ultimate execution.

Step 2 would be initiated following a decision by Yukon Energy to proceed with the development of the CES. Draft service contracts have been developed and would be presented to customers that signed MOUs for negotiation and execution.

12 Risk Management

The following sections of the report outline risks involved in development of CES and recommend mitigation strategies. These risks that apply to a CES can result in the system having less net value than anticipated.

Certain risks with respect to planning, safety and the environment can be mitigated simply through compliance with Bylaws or regulations.

The various risks and related regulations are discussed below generally in the sequence in which they are commonly encountered during the course of CES project development:

1. Planning
2. Marketing
3. Contracts and Pricing
4. Safety
5. Environment
6. Design
7. Construction
8. Operations

12.1 Planning

Community energy system developers need to know that they will be able to obtain planning approvals required to implement a proposed project, and the expected timeline. The following discussion highlights some of the key items that should be understood.

12.1.1 Zoning

The zoning Bylaw dictates land use. For any specific location, an energy centre may be explicitly or implicitly permitted or not or there may be restrictions, such as on the height of a stack or on outside storage (that could impact a biomass project).

After the technical concepts for the energy centres have been finalized, advice from local planning experts will be needed to determine whether zoning would permit the type of CE facilities that are contemplated. If not permitted, the next issue to be decided would be the least cost and shortest route to secure compliance, e.g. request for a change to the zoning Bylaw, a minor variance, find a different site or modify the technical concept.

The proposed concept has mitigated this risk by:

- Implementing P1 using existing boiler capacity
- Implementing P2 as the alternative energy centre at a location adjacent an existing power plant
- Implementing P3 as a simple, boiler-only energy centre in the downtown core

12.1.2 Development Permit and Building Permit

The municipal planning process usually includes site control in the form of a Development Permit and a Building Permit.

Application for a Development Permit can and should be made soon after engineering has proceeded to the point where a reasonably stable site layout can be produced.

A Building Permit would be required for a new energy centre, as for any new construction. Schedule and timelines to obtain building permit need to be indentified early as this could be on the project critical path.

12.1.3 Municipal Consent/Right of Way Agreement

The distribution systems of CES are most conveniently located to the greatest extent possible in municipal rights-of-way and other government controlled land, thereby minimizing the extent of easements required from private land owners. An Access Agreement is typically required with the municipality.

Any pipe routing not on municipal road allowance would require easements or other similar property agreement with the private landowner, which could introduce additional cost and delays.

Consultation with municipal planning staff is recommended to ensure full understanding of the process, timelines and potential cost of obtaining a Municipal Access Agreement for the contemplated route of the thermal distribution system.

12.2 Marketing

After completion of the feasibility study and after having made a decision to proceed to develop a new CES, marketing is generally the first project development activity. The degree of success in marketing will impact project definition, hence detailed design.

Marketing has certain risks that should be recognized and addressed because failure to achieve marketing objectives may bring the development to a halt, or produce unsatisfactory financial results.

Development of a CES is a relatively capital-intensive undertaking. Further, capital costs are “front-loaded” because of the relatively high costs of building an energy centre and installing the main distribution piping in the early years in contrast to the much lower cost of adding customers in later years with relatively short, smaller diameter pipe branches. Given these characteristics, a low level of success in marketing to targeted customers is a fundamental risk in development of a CES that could result in project cancellation, deferment or lower revenues than necessary to cover costs, including debt.

Mitigating marketing risks and the resultant impact on financial performance is the first major risk decision to be made.

An important first step to reducing marketing risks is to properly target the potential customers who have the greatest likelihood of taking service. This entails an accurate understanding of their avoidable costs relative to the costs of connection, including any modifications to the internal building systems.

Reducing marketing risk by more competitive pricing can reduce financial performance, whereas taking on more marketing risk by keeping a higher price regime can increase financial performance.

One marketing risk mitigation strategy is to obtain contracts from the Government of Yukon and City of Whitehorse buildings prior to proceeding with construction. This strategy reduces the overall financial risk by securing at least some revenue prior to project commitment. The anchor customers should be carefully chosen for their ability to influence the remaining potential customers. Also, this strategy works best when the incremental cost of serving new customers is less than the cost of serving the anchor customers (which would normally be the case because additional branch lines and energy transfer stations need relatively minor increments of capital). Many existing CES utilized this strategy initially.

Price cutting in general, which emphasizes customer "savings" from existing costs, is not recommended as a marketing risk mitigation strategy. It typically uses a feasibility study performed by the CES to identify "savings". The problems in practice are that:

i. The customers are skeptical that the savings are real and the truth is that they are difficult to prove or disprove
ii. The customers always want even more savings.

This strategy has led to excessive price cutting resulting in poor financial performance and should be avoided. It should be remembered that making sales agreements supposedly "confidential" does not mean that other interested parties will not find out what they need to know to negotiate the lowest available price.

Another common marketing risk mitigation strategy is to undertake an intense "kick-off" campaign to sign up customers. This is most useful where a large number of customers are anticipated such as in a downtown area. This strategy uses communications, advertising and public relations to build marketing momentum. This strategy has been used successfully by some of the newest downtown CES.

The following discussion identifies customer behaviours that may influence the marketing risk and require responses or decisions by the CE developer.

12.2.1 "Wait and See" Attitude

Some prospects may be reluctant to contract for CE service in the early years of system development because the idea of such a service is new to them. Many people are reluctant to be "early adopters" of new technologies or services, preferring to wait and see how it works for others. Successful marketing to such prospects requires education about the extent of CE use by entities they know or recognize (Government of Yukon), and achievement of credibility that the owners and operators have the expertise, and financial capability, to successfully develop and reliably operate the CES.

12.2.2 New Plants

A prospect may indicate a desire to continue owning and operating their current on-site plant system for any of a number of reasons, the more so if it is relatively new. As a result, there may be little or no capital avoidance value (since replacement is believed to be far off into the future), which seriously detracts from the total value provided by CE.

For buildings with relatively newer plants, a potential win/win response may be to lease their plant capacity for peaking and back-up, thereby procuring needed capacity for these purposes and reducing these customers' net costs of district energy. As the leased equipment ages, they can eventually become regular customers.

12.2.3 Coordination with Developers

Private sector developers for new construction and owners of existing buildings, each advised by their technical advisors must buy-in to CE because coordination of their activities with those of the CES is essential for it to be successful. Risks include new construction that could otherwise connect being designed for on-site heating, or, in the case of existing buildings, replacements and refurbishments being made, which could be avoided by connection to CE.

Mitigation measures include good two-way communication followed by system planning to enable the proposed CES to optimally serve prospective customers in a timely and economic way. Since connection to CE is a major procurement decision for any developer or building owner and since a healthy CES will be a major benefit to the community, it is appropriate that senior community leaders, including the highest staff and elected representatives, take an active role in promotion to the relevant decision makers in the development and property companies. If sold at a high-level, these decision makers will then ensure that their management and technical advisors work closely with the CES staff to achieve a successful result, i.e. connection to CE in preference to on-site heating.

12.2.4 Design of Internal HVAC Systems

After having secured the intent of developers and building owners to connect, the next challenge is to ensure that HVAC systems are designed to be compatible with an efficient CES. This may mean working with wider differences in temperature (ΔT) than the technical advisors are used to (and all that implies, such as no three-way valves and variable flow) and the use of lower temperatures.

The district heating system must be capable of meeting the requirement of the highest temperature needed by any customer on the secondary side and the blended return temperature on the primary side will determine how much energy can be recovered from any given energy source.

There is a trend in the design of modern district heating systems to use as low supply and return temperatures as possible in order to maximize use of low environmental impact energy sources. There is an economic trade-off between that objective and capital cost minimization through maximization of ΔT between supply and return, bearing in mind severe practical limitations on the possibilities for lowering return temperatures of older buildings.

These details should be provided early in discussions with prospective customers. The topic needs to be stressed during design meetings and repeated often, as experience has shown that conventional HVAC advisors will tend to design internal systems that do not allow the desired primary temperature profiles and this can limit system capacity and efficiency.

Selection of the best system operating temperature profile in consultation with potential customers and their advisors is an important outcome of the marketing phase of the project.

12.2.5 Recovery of Capital Investment from Revenue Stream

There are two issues:

1. How long it takes to pay back the capital investment
2. How well the monthly expenses, including debt service, are covered by the revenue stream

Some of the capital for CE is sometimes recovered upfront from building developers (in the form of connection fees), but it is usually at risk pending commencement of building construction. From the building developer's view-point they would not normally need to pay for heating equipment until the latter stages of construction so expect that connection fees should be payable on a similar timeframe.

Part of the original capital commitment could be recoverable from contracted revenue from the first anchor customer(s) that trigger(s) the need for CE construction to start. CE construction should not be committed until there is a significant customer commitment. The balance would be at risk pending commitments from additional customers.

The risk can be explored with sensitivity analysis. This analysis can show, for example, the relative impact in terms of number of % points off the expected internal rate of return (IRR) over a 25 year period that would be caused by delays in additional customer connections. When using variances in IRR as a criterion to measure risk, shorter planning horizons can unfairly represent the financial results if there is a build-up period of 5 - 10 years. Financial results are materially more positive viewed over a longer time period when there is a long build-out period, much more so than for projects where all the investment is made up front and all the revenue starts soon afterwards. The delay can be expressed in years of delay from the expected plan.

Generally, such analysis that have been done for greenfield situations have shown, not unexpectedly, that relatively minor delays or slightly lower rates of customer connection, do not have a material impact on results over the long-term. But if the CES is started with a few customers and then new connections essentially come to a halt and do not resume for a lengthy period, e.g. a decade, the financial results of a CES can be severely impacted if it has committed a large amount of capital upfront based on the expectation of steady continued development. The risk assessment relates to long-term development trends and would be very site specific.

The risk is mitigated to the extent that it can be planned that as large a portion as possible of the initial capacity will be covered by committed customers as soon as possible.

A strategy that has been used in circumstances where one customer building was built significantly in advance of others is to provide interim energy sources. The downside is that there is virtually no net capital recovery from decommissioning the interim facility.

12.2.6 Marketing Risks Summary

Overall, the key to minimizing marketing risks is a flexible marketing approach that focuses on value rather than price and which reflects a thorough understanding of buyers, their behavior and the technical constraints and opportunities posed by a specific set of target customers.

12.3 Contracts and Pricing

As an outcome of successful marketing, customers may be willing to enter contracts for CE service. At that point, there are several risks to subsequent successful business operations of the CES that should be addressed in the contracts that are negotiated.

12.3.1 Contract Term

It is recommended that the term of the customer contracts be long-term, preferably of a length consistent with amortization of capital costs, such as 20 years. Generally, variable costs, mainly energy costs, are handled as a pass-through on top of a fixed charge to cover fixed costs. By signing the long-term contract a credit-worthy customer provides assurance to the CES that the customer's proportional share of the CES fixed costs, including debt obligations, will be covered. And there will be provisions to cover these costs even in the event that the customer ceases to take service during the contract period, unless the CES is at fault.

12.3.2 Billing Cycle

Billing is normally done on a monthly basis.

12.3.3 Open Book vs. Closed Book Pricing

An Open Book pricing strategy provides the customer with direct knowledge of the CES costs. Rate components fluctuate directly with the appropriate costs. This strategy may reduce financial risk but may limit profitability. This pricing strategy has a mixed impact on marketing risks. A Closed Book pricing strategy provides the customer with no knowledge of underlying costs. Rate components are fixed by contract and fluctuate by contractual escalation clauses. This strategy increases financial risk but may allow for a higher return on investment. Open Book pricing on variable cost rate components is typical in the industry.

12.3.4 One-Part Rate

If the rate structure is limited to a single rate per Mega-Watt-hour, there will be a poor match of monthly cash flow to monthly costs, and risk of inadequate revenues if the weather is milder than expected or reduced occupancy or energy conservation measures reduce energy demand.

12.3.5 Two-Part Rate

If a two-part rate is chosen (i.e. fixed and variable rate), challenges in marketing and ongoing customer relations are possible. However, a two-part rate makes sense from a cash flow standpoint, and is the norm in the industry. It provides a basis for tying prices to related costs, providing appropriate signals to the customer. For example, capacity charges motivate customers to not contract for excessive capacity and possibly take steps to reduce their peak demand, which frees the CES to sell this capacity to others.

On the other hand, customers may find it difficult to understand why they must pay a significant part of their annual energy costs in a fixed monthly charge, even when they are not consuming much energy. Although electricity and gas rates usually have similar provisions, they tend to be not as pronounced as for CE with its relatively high fixed cost characteristic. This should be addressed through a specific and well-designed communications effort during the contract negotiations.

12.3.6 Connection Fees

Connection Fees have been favoured by some CE companies as part of the overall rate package especially for situations where the building developer and eventual building owners are different. The classic example is for Condominium Corporations, or school boards. This only applies to the new developments.

The problem that connection fees address is that while the building developer enjoys the benefit of saving capital that would otherwise be spent on heating plant, this benefit has been seen to be not transferred to the condominium buyers, who are then left to pay the capital component of CE in on-going energy bills, whereas without CE the capital costs of in-building heating equipment would have been included in the price of the condo unit. As a result it can seem that CE is costing consumers significantly more than conventional heating.

It was considered better to recover the benefit of avoided capital up-front directly from the developer and then have a lower fixed payment based on only the on-going fixed operation and maintenance cost that was avoided. But this tends to have a negative effect on the total value of the revenue stream long-term because revenue from connection fees cease once all customers are connected whereas the escalating fixed payments would continue and will probably continue past the 20 year initial contract terms, because almost all customers will renew.

One mitigation measure that is incorporated in some service agreements is a substantial renewal fee that is supposed to represent the customer's avoided replacement costs. While this seems to make sense from the CE company perspective, the longer term experience of this approach is untested.

12.3.7 Rates Related to Customer Avoided Costs

In the development of several CES, the CE owner has attempted to explain the rationale for customers' rates as based on costs the customer avoids by connection to CE as opposed to BAU. While this makes sense from an economic perspective, experience has shown that, in practice, it runs into the very human tendency to minimize the costs of alternatives to anything that someone is trying to sell. Since the subject is avoidance of *future* costs, there is strictly no way to accurately predict precisely what those future costs would be (indeed one of the benefits of CE is mitigation of this risk for customers) and there is a tendency to underestimate capital and non-fuel operation and maintenance costs.

Whereas avoided costs (BAU) have sometimes been useful in explaining CE service costs, over reliance on this approach in detail poses pitfalls, e.g. if it encourages arguments about estimates of line items that cannot be predicted with accuracy. It is better to stress that from a bottom line perspective CE service costs are not too different in total from BAU costs and whatever difference may exist, if it is negative, is inconsequential in relation to both the total costs of ownership of a building or condo unit and in relation to the total value of CE.

12.3.8 Initial Contract Demand

There are risks associated with establishing the initial contract demand under a two-part rate:

1. If the contract demand is too high, it increases the marketing challenge
2. If the contract demand is too low, there may be inadequate capacity to meet the actual peak demand

Employing a consulting team with experience in designing and providing operations support to existing systems will help minimize the risk.

12.4 Safety

The same safety principles apply as for any type of construction. A few issues of particular relevance for CE are mentioned as follows.

The greatest safety hazards associated with CE tend to be associated with the energy conversion component of the CES, not the thermal distribution and energy transfer stations in customer buildings.

The thermal distribution and energy transfer systems are closed loops operated at moderate temperatures and pressures. They are insulated and in the case of thermal distribution mostly buried. Pressure is a hazard and this is addressed in regulations. Steam systems are subject to water hammer and can cause personal injury in the case of catastrophic release but modern district heating systems would be based on hot water distribution which is far less hazardous in these respects. The trenches that are excavated to lay distribution pipe can in some cases be regarded as enclosed spaces for which that category of safety concern exists.

The energy conversion component of district energy is usually conducted in an energy centre that should be operated in accordance with strict safety and security procedures, similar to an electricity generating station. Indeed, one of the benefits of CE is to remove the inherently hazardous energy conversion process from buildings used by the general public. Those buildings are then made free from combustible fuels.

The hazards of electrical safety, pressure vessels, use of natural gas and workplace chemicals are covered by provincial regulations.

Because of these hazards, the CE company should be regarded as an operating utility with staff that may be few in number but appropriately experienced and qualified.

12.5 Environmental

Construction and operation of CES of the type contemplated does not involve significant risks to the environment or risks of non-compliance with environmental regulations. A CES centralizes fuel storage and combustion at a central source versus multiple smaller storage systems in the building as usual case. The result is that the CES can significantly reduce the communities overall environmental risk associated with thermal energy production.

Noise and emissions from the energy centre will be subject to provincial regulation, which means the energy centre cannot be placed in operation until it is demonstrated that the design meets limits as specified in the regulations. It will be monitored in operation to ensure compliance.

The distribution pipe system (DPS) is a closed loop that contains water with few chemicals such that it can be discharged to natural water courses or the sewer if necessary. The main occasion that water would be discharged from the DPS would be flushing water during commissioning and the chemicals involved in that exercise would be controlled careful to ensure compliance with environmental regulations.

Leaks would be rare for a properly designed system and monitored by a leak detection system to facilitate early repair.

12.6 Design

12.6.1 Functionality of Design

A successful CES requires the integration of plants, piping, valves, and pumps, into a smoothly functioning whole. This must include design of a piping system with adequate valving, supply points, and use of proven materials. If the design team lacks experience and expertise in CE, the integrated components may not function effectively together.

12.6.2 Equipment Quality

Risks related to equipment component design or manufacturing can be minimized by:

1. Ensuring that the design team is thoroughly familiar with CE equipment and vendor alternatives
2. Carefully developing equipment procurement contracts
3. Using proven technology

12.6.3 Underestimating Energy Demand

To the extent that energy demand can be accurately anticipated, reliability risks associated with inadequate capacity and economic risks associated with over-capacity can be minimized. The CE service contract should establish the peak energy capacity which the CES will deliver, based on stated climate conditions. It may be undesirable from a marketing perspective to establish too high a contract demand. However, there is a risk that extreme weather events beyond the stated conditions may occur, and the system needs to make a conscious decision regarding the safety margin for extreme events and mutual expectations in such events.

12.6.4 Design-Related Economic Risks

There are also long-term economic risks associated with decisions made at the design stage, including:

1. Installation of more plant capacity than required
2. Correct sizing of individual unit capacities to adequately and efficiently serve the project load profile
3. Reduced distribution system capacity due to inaccurate estimation of the temperature difference between supply and return
4. Direct vs. indirect customer connections
5. Control flexibility

12.6.5 Overestimation of Plant Capacity Requirements

Determination of the appropriate plant capacity requires a solid understanding of both the peak energy demand and the demand patterns of individual buildings. It is common to find that the customer's consulting engineer overestimates the peak demand, based on prudent engineering factors which are designed to ensure that the building needs will always be met in an individual building plant. While this approach is prudent from the standpoint of the consulting engineer, it generally results in overestimation of the peak demand. In addition, not all buildings experience their peak demand at the same time, due to different building physical characteristics and use patterns. The "diversity factor" is the ratio of the total instantaneous peak demand on the system to the sum of individual building peaks.

12.6.6 Reduced Distribution Capacity

The capacity of the distribution system is directly related to the temperature difference (ΔT) between supply and return water. To the extent that the actual ΔT is lower than anticipated, the capacity of the distribution system is diminished. The ΔT in a given building depends on the design and operation of the building energy system. Risks of inadequate ΔT can be minimized by:

1. Educating potential customers about the importance of ΔT
2. Working with customer technical designers during the design phase to ensure proper design
3. Implementing ongoing communication and training with building operating personnel
4. Addressing ΔT in the customer contract, potentially including penalties for low ΔT

Further, pipe sizing should have the ability to serve additional customer load from the combination of production and storage capacity, which may increase for various reasons.

12.7 Construction and Development

12.7.1 Underground Congestion

With underground construction a key element in developing a CES, a significant risk is higher than anticipated costs due to unforeseen congestion in underground services already in the street. This risk can be mitigated by working closely with existing utilities and utilizing an experienced contractor. To the extent that good data on underground service locations are lacking, safety margins should be incorporated into the construction budget and schedule.

12.7.2 Public Relations

Construction of the DPS results in closing lanes to traffic, which can pose public relations risks. The inconvenience of restricted traffic can lead to negative feelings by the public and the municipal government. Going the extra mile to proactively address potential concerns will pay many dividends. Recommendations include:

1. Communicate early and often with the potentially affected parties (building and business managers, city government, and the general public)
2. Include affected parties in planning
3. Listen to and act on concerns whenever possible

12.7.3 Right-of-Way Fees

Another potential cost risk relates to additional fees for construction in city street rights-of-way, as some cities have proposed or implemented. Municipalities generally view CE positively as an investment in downtown infrastructure. Right-of-way fees can reduce the competitiveness of CE so a balance of municipal objectives is necessary. This risk is mitigated if the grantor of the right-of-way is the same as the owner of the CES.

12.7.4 Start-up Issues

CES personnel would normally, together with the CES chief operator, commission the system. This includes the flushing of the DPS, verification of energy centre operation and performance, and verification of proper control at the building interfaces (ETS). It is important to work closely with the building operators to avoid any problems during this critical time.

12.7.5 General Construction Issues

As with any other facility construction project, there are risks associated with unforeseen conditions, accidents or contractor performance, leading to higher costs, delayed completion or quality control problems. Addressing these risks is fundamentally no different than other facility construction-related risks, for example:

1. Using reputable contractors and vendors under strong contract
2. A thorough procedure of pre-operational equipment and system checks, integrated with the construction process.

This is especially critical for DPS construction because this is a more specialized area and because of the high costs of rectifying problems. A summary of common construction risk, not particular to CE, is given in Table 47.

Table 47 - Summary of Common Construction Risks

Risks	Measures to Control Risks
Completion	• Turnkey contracts • Liquidated damages
Failure to meet specifications	• Performance bonds
Costs over budget	• Control of change orders
Force majeure and other delays	• Clear criteria for completion • Completion undertaking by proponents • Thorough and timely reporting by project manager

12.8 Operations

12.8.1 Delays in Converting Buildings

Initiation of CE service requires timely action not only by the CES but also by the customer, who must convert his building system for interface with the district loop. As a result, there are risks of reduced revenues due to delays in converting and connecting buildings. These risks can be reduced through ongoing customer communication and technical assistance during the building conversion process, as well as through contract provisions requiring initiation of payments at a date certain.

12.8.2 Metering

Appropriate billing of CE customers requires accurate metering. Risks related to inaccurate metering include: 1) low revenues, resulting in diminished profits; or 2) high revenues, resulting in potential customer relations problems. These risks can be minimized through procurement of high-quality meters and a strong program for maintaining them. The electromagnetic flow meter (or magmeter) is a high quality meter. Magmeters have low pressure drops, good rangeability and accuracy while requiring very little maintenance.

All thermal energy meters should comply with the Canadian Standards Association (CSA) heat metering standard (CSA C.900), as may be amended or replaced from time to time. This is an adaptation of European Standard EN1434 with Canadian deviations.

12.8.3 Building Shutdown

There are also risks of reduced revenues due to shut-down or demolition of customer buildings. These risks can be minimized through contractual provisions requiring recovery of the CES costs for connecting the building and other fixed costs which are unrecovered at the time of the shut-down or demolition.

12.8.4 General Cost Risks

As with any business, there are risks of inflation in operating costs. These risks can be minimized through escalation provisions in the customer contract. Rates typically consist of up to three rate components designed to recover: fixed operation, maintenance and administration costs, fuel and other variable costs and fixed amortization costs. Each rate component and escalation provision would be set by contract. Fixed operation and maintenance costs would be escalated by some standard inflation indices. Fuel and other variable costs would be adjusted from some base to track actual cost.

12.8.5 General Credit Risks

As with other energy service business, there are customer credit risks, which can be minimized through the customer contract provisions allowing service termination for non-payment, the posting of bonds or payment of deposits. Common operations risks are summarizes in Table 48.

Table 48 - Common Operations Risks

Risks	Measures to Control Risks
Failure of any of the participants whose commitments are relied upon to perform - (sponsors, contractors, suppliers, customers, insurers, guarantors)	• Performance bonds, letters of credit per requirements. • Involvement of experienced, competent participants in their respective fields, and, possibly, turn-key supply/design/build for power or combined heat and power island) • Credit worthy customers (government owned buildings are considered to have high credit-worthiness)
Closure of the Energy Source	• Contractual protection in energy purchase agreement

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Appendix A Preliminary Load and Energy

A.1 Preliminary Load and Energy Assumptions

Preliminary Load and Energy Assumptions

Peak Demand and Energy Intensity Values

Once the buildings had been classified into each type, energy intensity values were developed for each classification. Many sources, such as the ones listed below, were consulted to assign the appropriate load and energy intensity values to the respective building type:

- NRCAN
- Environment Canada
- Previous northern climate studies by FVB Energy
- Actual fuel consumption data obtained from surveyed buildings
- Actual data from other CES customers throughout Canada

Table 1 shows the Whitehorse energy intensity factors used for each classification type. The intensity factors, in association with the building floor areas, produced the space heating and domestic hot water (DHW) loads and energy for each identified building.

Table 1 - Whitehorse Load and Energy Intensity Factors

Classification	Space Heating Peak (W/m^2)	Space Heating Energy (kWh/m^2)	DHW Peak (W/m^2)	DHW Energy (kWh/m^2)	Total Peak (W/m^2)	Total Energy (kWh/m^2)
MURB	85	185	10	30	85	215
Commercial	90	180	1	8	90	188
School / Community	90	190	10	20	90	210
Recreation / Pool	200	450	20	50	200	500
Office	85	180	1	8	85	188
Retail	90	180	1	8	90	188
Hospital	150	350	20	50	150	400
Hotel	95	200	20	40	95	240

The total peak intensity factor does not include the DHW peak because the DHW usage is very intermittent and has a marginal effect on the overall peak heating demand. The DHW annual energy usage however is not generally negligible and is considered in the total energy usage of most buildings.

Seasonal Boiler Efficiency (SBE)

Fuel consumption data was provided for numerous government-owned and private buildings. This fuel consumption data was used to determine the total annual energy usage of the building after applying a seasonal boiler efficiency[1]. This calculated energy consumption was used wherever data was available and the actual fuel data helped to estimate the energy intensities used for various types of buildings.

Based on reasonable average efficiency numbers obtained from FVB's extensive experience with converting buildings to CES, an average seasonal boiler efficiency of 65% was assumed for the majority of the buildings with fuel data. A few buildings surveyed were operating boilers greater than 50 years old. The seasonal boiler efficiency of these was lowered to 60% due to the assumed long term performance degradation.

Load Diversification Factor

For the Whitehorse CES, the load diversification factor[2] has been estimated to be 85% of the total connected load.

Heating Load and Energy Summary

Table 2 shows a summary of their identified potential load and energy requirements. It should be noted that the loads and energy presented in Table 2 are the total of all the identified buildings in each Zone except the buildings that produced an estimated demand less than 100 kW.

With the screening process to follow, a number of the identified buildings will be screened out based on their candidacy in each CES Concept scenario. The screening process may also combine Zones or buildings from different Zones into one CES scenario.

Table 2- Whitehorse Zone Identified Loads and Energy

Zone	Total Identified Load (kW)	Total Diversified Load - 85% (kW)	Total Identified Energy Consumption (MWh)
Zone 1 - Lewes Boulevard	5,940	5,050	13,600
Zone 2 - Hospital Road	3,340	2,840	8,500
Zone 3 - Downtown Core	15,620	13,280	35,000
Zone 5 - Range Road	4,140	3,520	8,100
Zone 6 - Airport	2,990	2,540	5,700
Zone 7 - Canada Games Centre	3,790	3,220	6,600

[1] The seasonal boiler efficiency is the result of combustion efficiency, part load efficiency, standby heat losses from cycling, load factors, and long term performance degradation caused by controls and heat transfer surface area fouling.

[2] Diversification of load is an inherent benefit of CES over conventional in-building systems, particularly where serving mixed-use buildings. The differing building types, occupancies and uses results in non-coincidental peaks.

Appendix B - Overall Concept Pre-Screening

B.1 Pre-Screening Assumptions

Pre-Screening Assumptions

Capital Costs

With the scenario parameters defined, it is now possible to assign capital costs required to construct the preferred CES. The high level unit costs are all inclusive except they do not include land costs or Owners soft costs such as project development and legal costs.

The costing is for preliminary screening only with sufficient accuracy to use for a cost comparison to determine a preferred scenario.

Distribution Piping System

The distribution piping system (DPS) includes all transmission piping, mains and branch piping. All sizing assumed an allowable pressure drop of 175 Pascals per meter and temperature difference between supply and return lines of 40°C.

The transmission and mains sizing is based on diversified loads (assumed to be 85% of contract load) delivered by the pipe, whereas the branch piping is sized based on the contract loads.

A typical cost is applied for the estimated length and size of pipe in the piping network.

Energy Transfer Stations

The equipment required to transfer the energy from the hot water in the piping to the customer is referred to as an energy transfer station (ETS). All costs associated reflect an in-direct connection based on 117°C Community Energy supply temperature. The capital amount is based on historical tenders and sizing is based on contract loads.

Energy Centre

The energy centre is assumed to provide base load heating through a biomass boiler system and provide peak heating through oil boilers. These assumptions do not reflect any bias towards an energy supply, but an educated estimate of the costs incurred in this assumed scenario. The intent is only to provide the framework to screen which scenario to pursue in more detail.

For this screening matrix, the base load (biomass) boilers were sized based on 1/3 of the total diversified load. The fuel oil peaking boilers are sized at 100% of the diversified load to account for redundancy in the system. However, it is assumed that 80% of the heating energy required in the system is provided by the base load (biomass) boilers. The fuel oil peaking boilers would provide the remaining 20% of the annual heating energy.

Annualized Capital

The total capital cost is annualized to determine yearly capital cost expenditure. These scenarios assume that the total cost of the capital is borrowed at 5.5% interest over a 25 year term. The resulting annual capital cost is shown in Table 1.

Table 1 - Annualized Capital Costs

Whitehorse - Total Cost Estimate per Zone	Scenario #1: Lewes Blvd Zone 1	Scenario #2: Hospital Road Zone 2	Scenario #3: Downtown Core Zone 3	Scenario #4: Range Road Zone 5	Scenario #5: Airport Zone 6	Scenario #6: Canada Games Centre Zone 7
Total Cost of Capital	$10,270,050	$5,779,900	$23,964,050	$8,962,200	$5,022,900	$8,299,500
Annualized Capital	$766,000	$431,000	$1,787,000	$668,000	$374,000	$619,000
Capital Reference $ per kW	$2,654 /kW	$1,818 /kW	$2,289 /kW	$2,269 /kW	$3,063 /kW	$2,243 /kW

Whitehorse - Total Cost Estimate per Zone	Scenario #7: Hospital and Lewes Blvd Zones 1 & 2	Scenario #8: Downtown Core and Hospital Zones 2 & 3	Scenario #9: Range Road & Canada Games Centre Zones 5 & 7	Scenario #10: Canada Games Centre - Revised Zone 7	Scenario #11: Lewes Blvd, Hospital and Downtown Core Zone 1, 2 & 3
Total Cost of Capital	$18,497,650	$31,193,800	$18,249,400	$9,889,850	$37,728,100
Annualized Capital	$1,379,000	$2,325,000	$1,360,000	$737,000	$2,813,000
Capital Reference $ per kW	$2,496 /kW	$2,272 /kW	$2,386 /kW	$2,178 /kW	$2,308 /kW

As shown, though other scenarios have a lower capital cost, Scenario #2 and Scenario #8 have low capital costs compared to the size of the assumed CES loads.

Utility Costs

The utility costs are based on the size of the equipment installed and the heating energy provided by the base load alternative capacity and peaking oil boilers. The utility costs include the operation and maintenance costs associated with running the energy centre.

It is assumed that there are no distribution heat losses and the electric cost component of running the system (i.e. distribution pumps, circulation pumps, controllers and other boiler parasitics) are not included at this level of detail.

Biomass - Baseload Heating

Biomass was selected as the fuel for the alternative heating fuel source. There are supply options for both wood pellets and wood chips within the region, and the cost estimates and fuel quality data is available for both options.

Wood Chips

The CES concepts were screened using woodchips as a base fuel using the following general assumptions:

- $150 per green tonne (Morrison Hershfield, 2011)
- 25% moisture content (as agreed by the steering committee)
- 20.6 GJ/tonne HHV (per bone dry tonne) (Morrison Hershfield, 2011)
- Seasonal boiler efficiency of 73%

Wood Pellets

A second set of scenarios was released, based on using wood pellets as a base fuel using the following general assumptions:

- $326 per green tonne
- 7% moisture content (Morrison Hershfield, 2011)
- 20.6 GJ/tonne HHV (per bone dry tonne)
- Seasonal boiler efficiency of 77%

Fuel Oil Peaking Boilers

Thermal energy not provided by the baseload boilers, is provided using highly efficient condensing boilers with the following general assumptions:

- $1.00 per liter of fuel oil
- 38.91 MJ/L heating value
- Seasonal boiler efficiency of 80%

Operation and Maintenance

The scenarios assume an operation and administration budget of $195,000 per year. For routine maintenance, there is a small budget dedicated to maintaining the energy centre equipment and the distribution equipment.

Business as Usual Revenue

To estimate the amount of revenue that can be charged to connecting customers was conservatively assumed at $185 per MWh of heating energy provided. This value takes into consideration an average customer with a contract load of 250 kW.

B.2 Pre-Screening Results with Varied Biomass Fuel Assumptions

Next, the screening matrix was recalculated using the same assumptions except changing the fuel source for the baseload biomass boilers to wood pellets. This addresses the sensitive of fuel cost and fuel quality and its effect on the payback period of this project, as shown below in the table below.

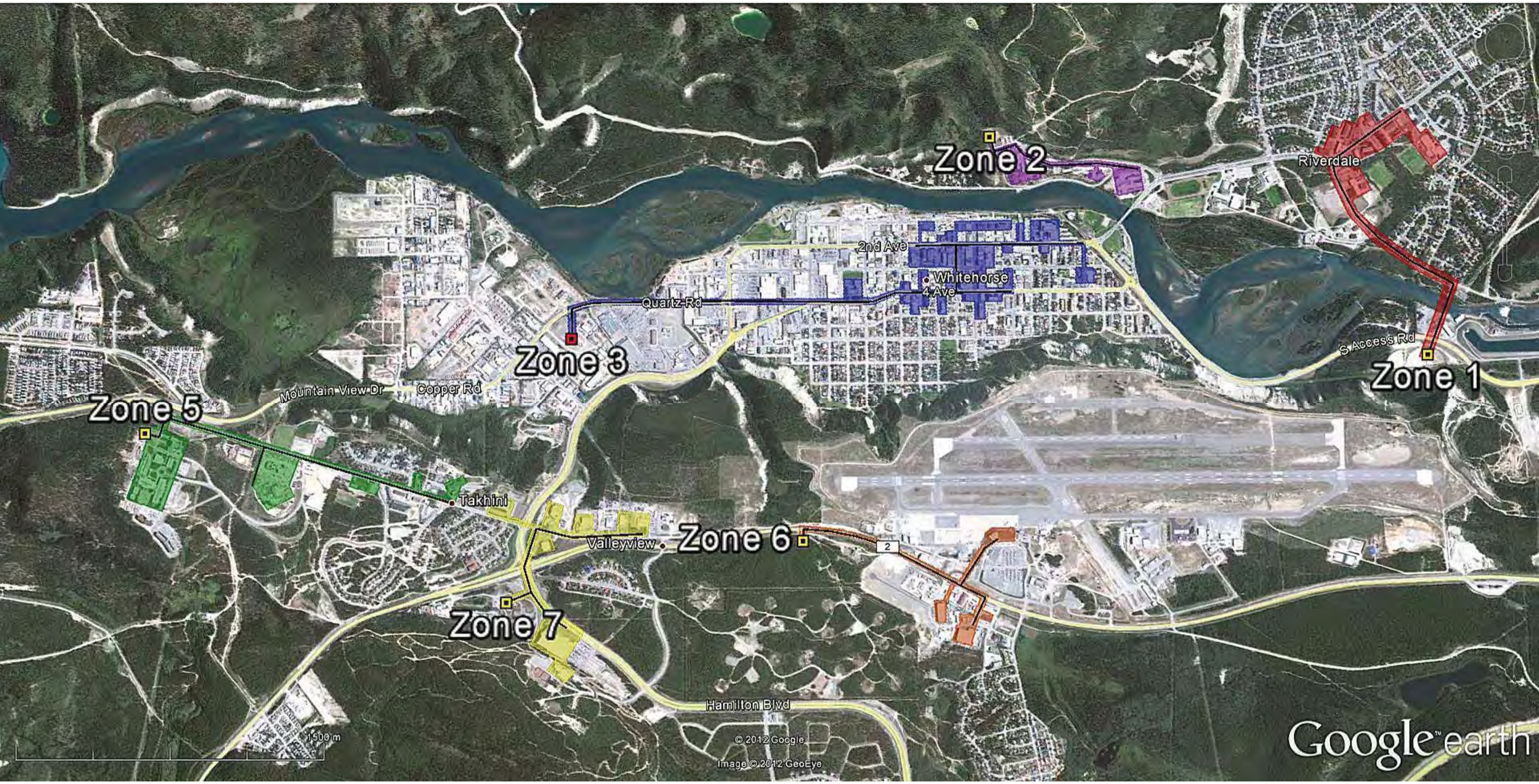
Table 49 - Simplified Payback Comparison between Biomass Fuel Assumptions

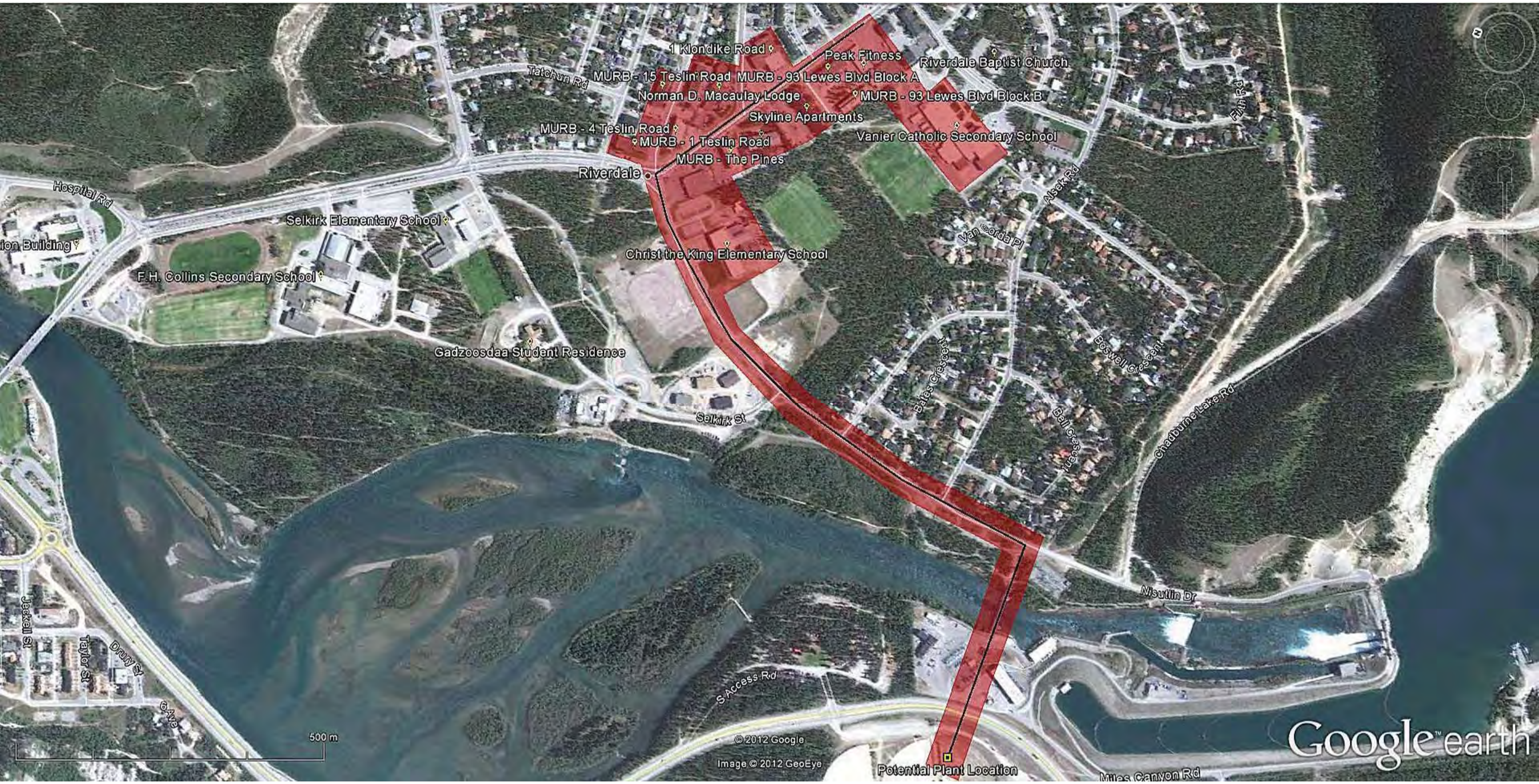
Whitehorse - Total Cost Estimate per Zone	Scenario #1: Lewes Blvd Zone 1	Scenario #2: Hospital Road Zone 2	Scenario #3: Downtown Core Zone 3	Scenario #4: Range Road Zone 5	Scenario #5: Airport Zone 6	Scenario #6: Canada Games Centre Zone 7
Simplified Payback -Wood Chips	13.5 yrs	7.7 yrs	10.4 yrs	14.8 yrs	>50 yrs	18.0 yrs
Simplified Payback - Wood Pellets	19.4 yrs	10.9 yrs	14.0 yrs	21.9 yrs	No Payment	27.8 yrs

Whitehorse - Total Cost Estimate per Zone	Scenario #7: Hospital and Lewes Blvd Zones 1 & 2	Scenario #8: Downtown Core and Hospital Zones 2 & 3	Scenario #9: Range Road & Canada Games Centre Zones 5 & 7	Scenario #10: Canada Games Centre - Revised Zone 7	Scenario #11: Lewes Blvd, Hospital and Downtown Core Zone 1, 2 & 3
Simplified Payback -Wood Chips	10.4 yrs	9.6 yrs	14.5 yrs	15.2 yrs	9.5 yrs
Simplified Payback - Wood Pellets	14.1 yrs	12.9 yrs	20.3 yrs	22.4 yrs	12.7 yrs

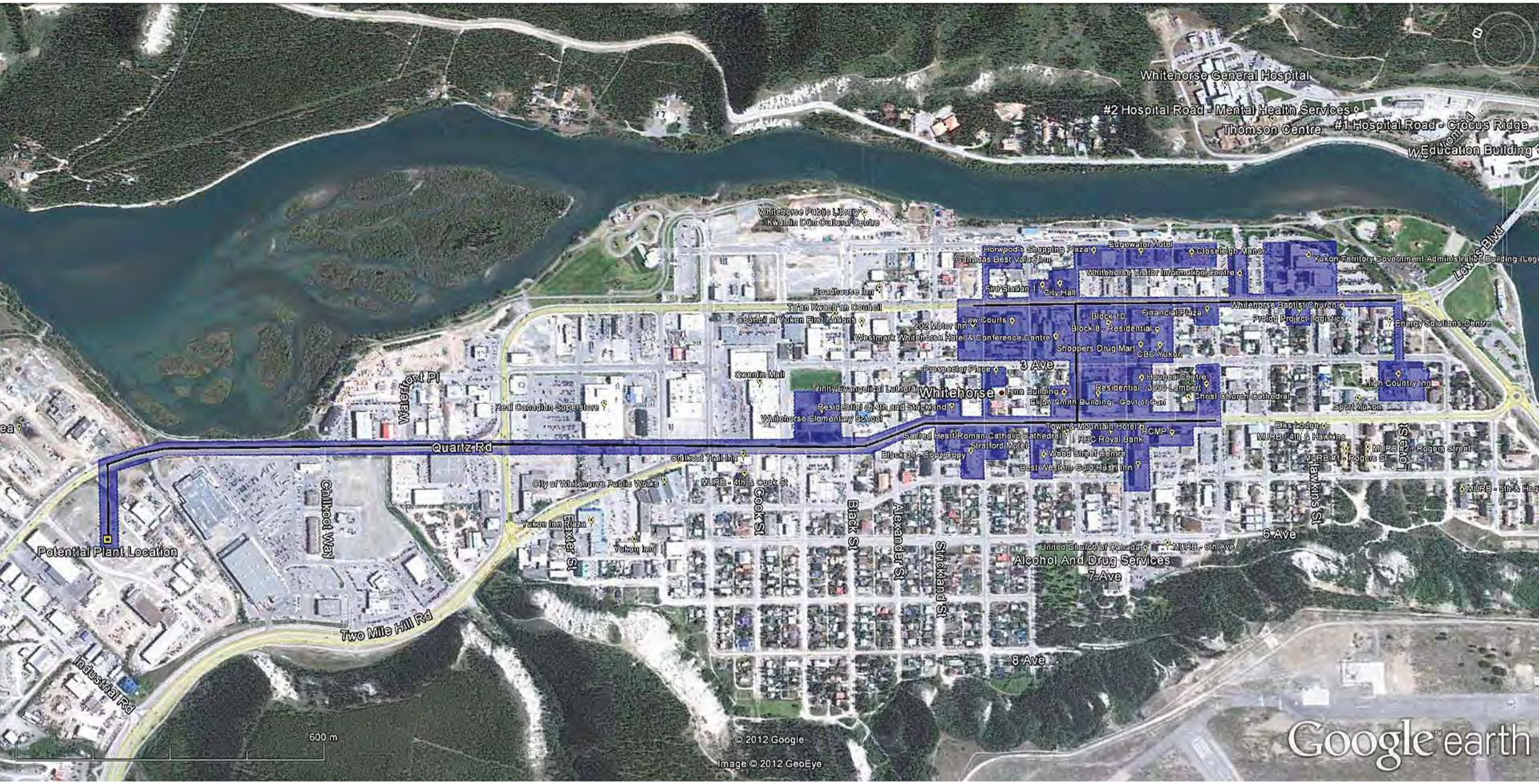
As shown, the payback period decreases with the higher cost of the fuel, however the relative ranking applies to both screening processes.

B.3 Pre-screening Zone Diagrams


Zone 2
Riverdale
2nd Ave
Whitehorse
4 Ave
Quartz Rd
Zone 3
S Access Rd
Zone 1
Mountain View Dr
Copper Rd
Zone 5
Takhini
Valleyview
Zone 6
2
Zone 7
Hamilton Blvd
1500 m
© 2012 Google
Image © 2012 GeoEye
Google earth


1 Klondike Road
Peak Fitness
Riverdale Baptist Church
MURB - 15 Teslin Road
MURB - 93 Lewes Blvd Block A
Norman D. Macaulay Lodge
MURB - 93 Lewes Blvd Block B
Skyline Apartments
MURB - 4 Teslin Road
MURB - 1 Teslin Road
Vanier Catholic Secondary School
MURB - The Pines
Riverdale
Tatchun Rd
Hospital Rd
Selkirk Elementary School
ion Building
F.H. Collins Secondary School
Christ the King Elementary School
Gadzoosdaa Student Residence
Van Gorda Pl
Alsek Rd
Boswell Crescent
Bates Crescent
Bell Crescent
Fifth Rd
Chadburne Lake Rd
Selkirk St
Nisutlin Dr
S Access Rd
Jeckell St
Taylor St
Drury St
6 Ave
500 m
© 2012 Google
Image © 2012 GeoEye
Potential Plant Location
Miles Canyon Rd
Google earth


Potential Plant Location
Whitehorse General Hospital
#4 Hospital Rd - Environmental Health Services
Thomson Centre
#2 Hospital Road - Mental Health Services
#1 Hospital Road - Crocus Ridge
Wickstrom Rd
Hospital Rd
Education Building
200 m
1 Ave
Hanson St
© 2012 Google
Image © 2012 GeoEye
Google earth


Whitehorse General Hospital
#2 Hospital Road - Mental Health Services
Thomson Centre
#1 Hospital Road - Crocus Ridge
Education Building
Lewes Blvd
Whitehorse Public Library
Kwanlin Dün Cultural Centre
Horwood's Shopping Plaza
Edgewater Hotel
Closeleigh Manor
Canadas Best Value Inn
Yukon Territory Government Administrative Building
Whitehorse Visitor Information Centre
Fire Station 1
City Hall
Roadhouse Inn
Ta'an Kwach'an Council
Council of Yukon First Nations
Whitehorse Baptist Church
Financial Plaza
Law Courts
Block 10
202 Motor Inn
Block 8 - Residential
Westmark Whitehorse Hotel & Conference Centre
Energy Solutions Centre
Shoppers Drug Mart
CBC Yukon
Prospector Place
3 Ave
Qwanlin Mall
Trinity Evangelical Lutheran
Whitehorse
Lynn Building
Residential - 3096 Lambert
Christ Church Cathedral
Elijah Smith Building - Govt of Can
Residential @ 4th and Strickland
Whitehorse Elementary School
Lion Country Inn
Sport Yukon
Waterfront Pl
Real Canadian Superstore
Town & Mountain Hotel
Sacred Heart Roman Catholic Cathedral
RCMP
RCC Royal Bank
Stratford Motel
Elks Lodge
MURB - 4th & Hawkins
Quartz Rd
Block 34 - Copy Copy
Wood Street Centre
MURB - Rogers Street
Chilkoot Trail Inn
Best Western Gold Rush Inn
MURB - Rogers St
City of Whitehorse Public Works
MURB - 4th & Cook St
Chilkoot Way
Cook St
Black St
Alexander St
Strickland St
Hawkins St
MURB - 6th & Hog
Yukon Inn Plaza
Baxter St
6 Ave
Potential Plant Location
Yukon Inn
United Church of Canada
MURB - 6th Ave
Alcohol And Drug Services
7 Ave
Two Mile Hill Rd
8 Ave
Industrial Rd
600 m
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Google earth


Potential Plant Location
Yukon College Ayamdigut Campus
Young Offenders Facility
New Correctional Centre
Whitehorse Correctional Centre
Takhini Elementary School
Barracks Apartments
Takhini Complex
Transportation Engineering Branch
Takhini
Takhini Arena
Public Safety Building
Mountain View Dr
Janice St
Crescent Dr
Copper Rd
Quartz Rd
Jasper Rd
Dieppe Dr
Ardeux Pl
College Dr
Range Rd
Two Mile Hill Rd
Hamilton Blvd
Klondike Hwy
Carpiquet Rd
Falaise Rd
Nijmegan Rd
Normandy Rd
Ortona Ave
Arnhem Rd
Cassino St
500 m
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Image © 2012 GeoEye
Google earth


Airport Terminal
Air North - Catering & Repair
Air North - Tent Hangers
Air North - Admin Bldg
Potential Plant Location
Barkley Grow Crescent
Otter Rd
Pilgrim Pl
Lodestar Ln
Yukon Transportation Museum
Kingbird Rd
Airport Chalet
Hillcrest
Environment Yukon
Yukon Beringia Interpretive Centre
Electra Crescent
Keith Plumbing & Heating
Burns Rd
Klondike Hwy
2
Northern Windows
Yukon Bible Fellowship
Terra Apartments
Apartments on Hillcrest Dr
Terra Apartments #2
Summit Rd
Sunset Dr N
Roundel Rd
Chalet Crescent
Hillcrest Dr
Hamilton Blvd
500 m
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College Dr
Dieppe Dr
Arlaux Pl
Takhini Elementary School
Barracks Apartments
Takhini Complex
Transportation Engineering Branch
Takhini
Takhini Arena
Two Mile Hill Rd
Public Safety Building
Inland Kenworth
Northwestel
Range Rd
Carpiquet Rd
Falaise Rd
Nijmegan Rd
Canada Post
Klondike Hwy
2
Valleyview
Saive Square
Normandy Rd
Ortona Ave
Valleyview Crescent
Valleyview Dr
Arnhem Rd
Cassino St
Potential Plant Location
Environment Canada
Canada Games Centre
Sumanik Dr
Mount McIntyre
500 m
© 2012 Google
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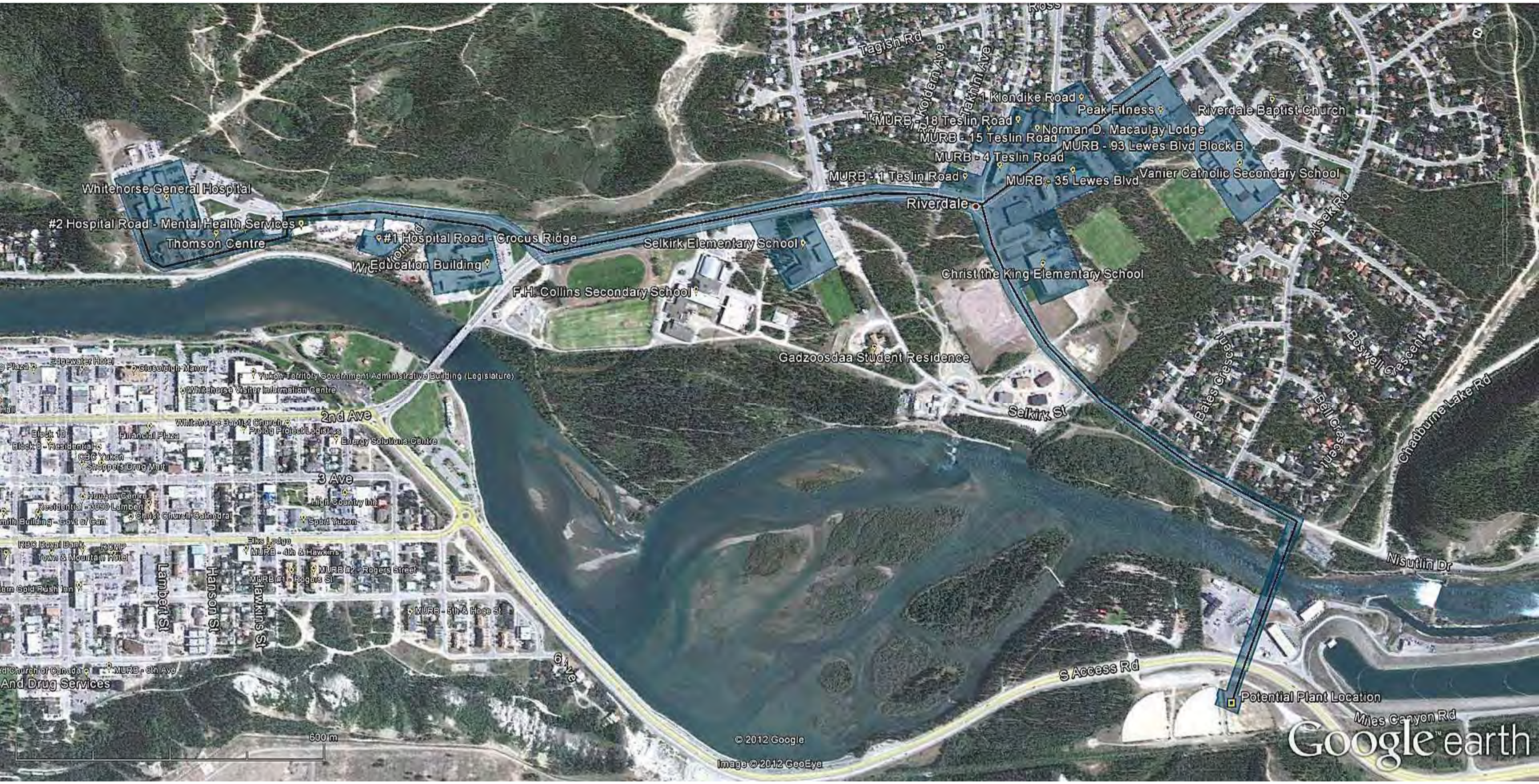
Google earth


Whitehorse General Hospital
#2 Hospital Road - Mental Health Services
Thomson Centre
#1 Hospital Road - Crocus Ridge
Education Building
F.H. Collins Secondary School
Selkirk Elementary School
Riverdale
MURB - 1 Teslin Road
MURB - 4 Teslin Road
MURB - 15 Teslin Road
MURB - 18 Teslin Road
1 Klondike Road
Peak Fitness
Norman D. Macaulay Lodge
MURB - 93 Lewes Blvd Block B
MURB - 35 Lewes Blvd
Riverdale Baptist Church
Vanier Catholic Secondary School
Christ the King Elementary School
Gadzoosdaa Student Residence
Tagish Rd
Alsek Rd
Boswell Crescent
Bell Crescent
Bates Crescent
Chadburne Lake Rd
Selkirk St
Nisutlin Dr
S Access Rd
Miles Canyon Rd
Potential Plant Location
2nd Ave
3 Ave
Lambert St
Hanson St
Hawkins St
Yukon Territory Government Administrative Building (Legislature)
Whitehorse Visitor Information Centre
Whitehorse Baptist Church
Prolog Project Logistics
Energy Solutions Centre
Financial Plaza
Christ Church Cathedral
Sport Yukon
High Country Inn
Elks Lodge
MURB - 4th & Hawkins
MURB #2 - Rogers Street
MURB #1 - Rogers St
MURB - 5th & Hoge St
MURB - 6th Ave
And Drug Services
600 m
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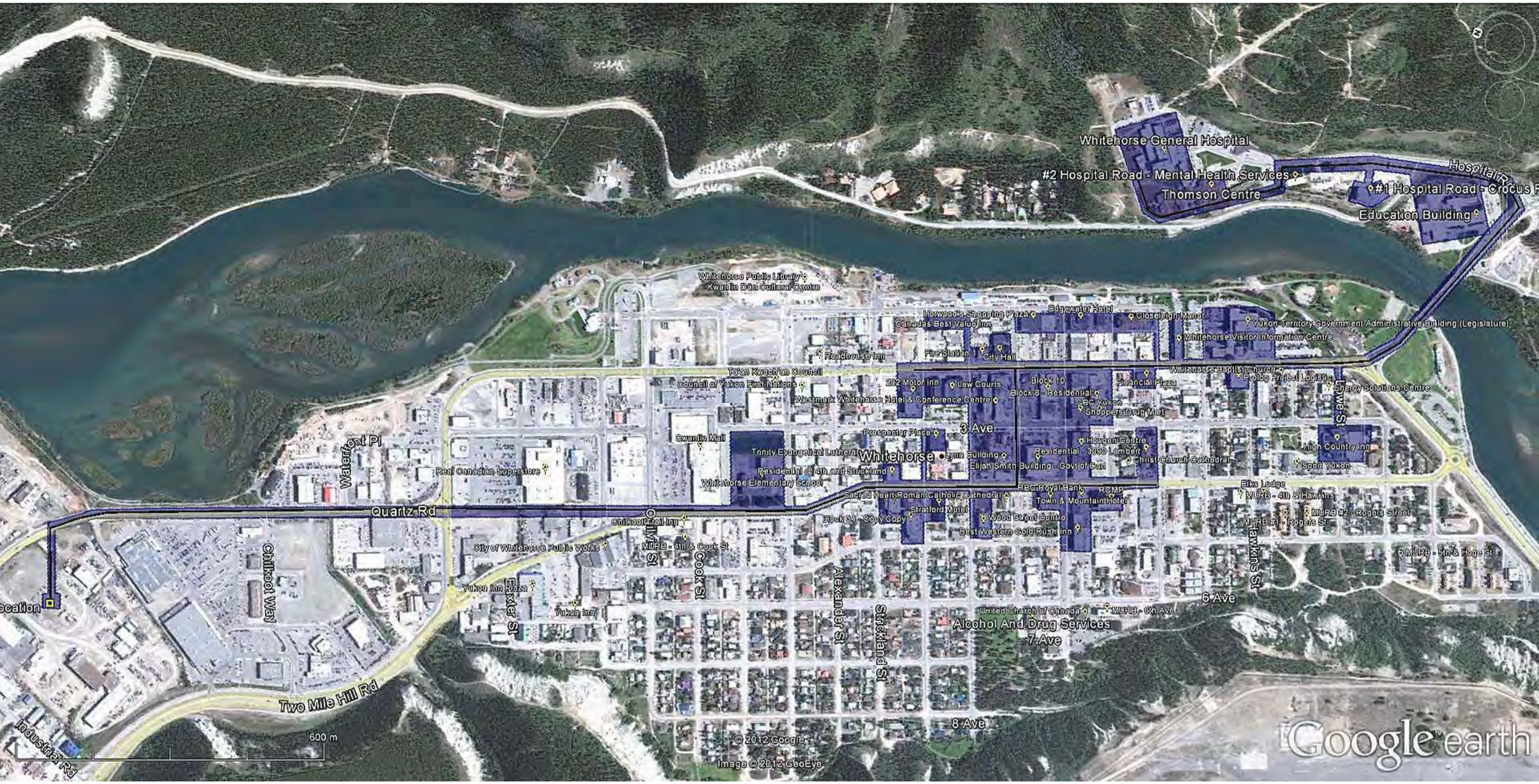
Whitehorse General Hospital
#2 Hospital Road - Mental Health Services
Thomson Centre
#1 Hospital Road - Crocus R
Hospital R
Education Building
Whitehorse Public Library
Kwanlin Dün Cultural Centre
Horwood's Shopping Plaza
Edgewater Hotel
Closeleigh Manor
Yukon Territory Government Administrative Building (Legislature)
Whitehorse Visitor Information Centre
Canadas Best Value Inn
Roadhouse Inn
Fire Station 1
City Hall
Ta'an Kwach'an Council
Council of Yukon First Nations
202 Motor Inn
Law Courts
Block 10
Block 8 - Residential
Financial Plaza
Whitehorse Baptist Church
Prolog Project Logistics
Energy Solutions Centre
Westmark Whitehorse Hotel & Conference Centre
CBC Yukon
Shoppers Drug Mart
Lowe St
3 Ave
Prospector Place
Qwanlin Mall
Trinity Evangelical Lutheran
Whitehorse
Lynn Building
Residential - 3090 Lambert
Elijah Smith Building - Govt of Can
Christ Church Cathedral
High Country Inn
Sport Yukon
Residential @ 4th and Strickland
Whitehorse Elementary School
Real Canadian Superstore
Waterfront Pl
RBC Royal Bank
RCMP
Elks Lodge
MURB - 4th & Hawkins
Sacred Heart Roman Catholic Cathedral
Town & Mountain Hotel
MURB #2 - Rogers Street
Quartz Rd
Chilkoot Trail Inn
Stratford Motel
Block 34 - Copy Copy
Wood Street Centre
MURB #1 - Rogers St
Best Western Gold Rush Inn
City of Whitehorse Public Works
MURB - 4th & Cook St
Ogilvie St
Cook St
Alexander St
Hawkins St
MURB - 5th & Hoge St
Chilkoot Way
ocation
Yukon Inn Plaza
Yukon Inn
Baxter St
Strickland St
6 Ave
United Church of Canada
MURB - 6th Ave
Alcohol And Drug Services
7 Ave
Two Mile Hill Rd
Industrial Rd
600 m
8 Ave
© 2012 Google
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Google earth


Mountain View Dr
Potential Plant Location
Young Offenders Facility
Yukon College Ayamdigut Campus
College Dr
New Correctional Centre
Whitehorse Correctional Centre
Takhini Elementary School
Dieppe Dr
Barracks Apartments
Transportation Engineering Branch
Takhini
Takhini Arena
Public Safety Building
Inland Kenworth
Northwestel
Range Rd
Canada Post
Valleyview
Jasper Rd
Two Mile Hill Rd
Carpiquet Rd
Falaise Rd
Nijmegan Rd
Seine Square
Ortona Ave
Arnhem Rd
Cassino St
Valleyview Crescent
Valleyview Dr
Sumanik Dr
Environment Canada
Canada Games Centre
Mount McIntyre
600 m
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Takhini Elementary School
Barracks Apartments
Takhini Complex
Transportation Engineering Branch
Takhini
Takhini Arena
Public Safety Building
Inland Kenworth
Northwestel
New Municipal Services Bldg
Canada Post
Range Rd
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Valleyview
Valleyview Crescent
Valleyview Dr
Potential Plant Location
Environment Canada
Canada Games Centre
Mount McIntyre
Sumanik Dr
Two Mile Hill Rd
Dieppe Dr
Alsace Pl
College Dr
Carpiquet Rd
Nijmegan Rd
Falaise Rd
Seine Square
Normandy Rd
Ortona Ave
Arnhem Rd
Cassino St
Hamilton Blvd
500 m
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Image © 2012 GeoEye
Google earth


Grey Mountain Primar
Kingdom Hall of Jehovah's Witnesses
1 Klondike Road
Peak Fitness
Riverdale Ba
MURB - 15 Teslin Road
MURB - 93 Lewes Blvd Block A
MURB - 4 Teslin Road
MURB - 1 Teslin Road
Vanier Catholic Secondary Schoo
Whitehorse General Hospital
#2 Hospital Road - Mental Health Services
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Selkirk Elementary School
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Stratford Motel
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MURB #1 - Rogers St
City of Whitehorse Public Works
Wood Street Centre
Best Western Gold Rush Inn
MURB - 4th & Cook St
MURB - 5th & Hoge St
Yukon Inn
MURB - 6th Ave
United Church of Canada
Alcohol And Drug Services
Potential Plant Location
750 m
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B.4 Pre-Screening Detailed Summary

Project:	Whitehorse District Energy System Feasibility Study
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy
Date:	March 21, 2012
Revision #:	1
Prepared by:	G. Saskiw
Reviewed by:	R. Doyle
Model #:	43
Data Source:	Means 2011 Q1, LOGSTOR Material Pricing from Feb 2011, FVB
Description:	Scenario Pre-Screening

Whitehorse - Total Cost Estimate per Zone	**Scenario #1: Lewes Blvd** **Zone 1**	**Scenario #2: Hospital Road** **Zone 2**	**Scenario #3: Downtown Core** **Zone 3**	**Scenario #4: Range Road** **Zone 5**	**Scenario #5: Airport** **Zone 6**	**Scenario #6: Canada Games Centre** **Zone 7**	**Scenario #7: Hospital and Lewes Blvd** **Zones 1 & 2**	**Scenario #8: Downtown Core and Hospital** **Zones 2 & 3**	**Scenario #9: Range Road & Canada Games Centre** **Zones 5 & 7**	**Scenario #10: Canada Games Centre - Revised** **Zone 7**	**Scenario #11: Lewes Blvd, Hospital and Downtown Core** **Zone 1, 2 & 3**
Loads and Energy											
Displaced Heating Energy (MWh)	8,942 MWh	8,510 MWh	23,333 MWh	7,640 MWh	2,670 MWh	6,400 MWh	18,200 MWh	31,851 MWh	14,040 MWh	8,150 MWh	38,404 MWh
Contract Load (kW)	3,870 kW	3,180 kW	10,468 kW	3,950 kW	1,640 kW	3,700 kW	7,410 kW	13,730 kW	7,650 kW	4,540 kW	16,348 kW
Diversified Load (kW)	3,290 kW	2,703 kW	8,898 kW	3,358 kW	1,394 kW	3,145 kW	6,299 kW	11,671 kW	6,503 kW	3,859 kW	13,896 kW
Energy Density (MWh/ha)	669 MWh/ha	875 MWh/ha	735 MWh/ha	225 MWh/ha	151 MWh/ha	254 MWh/ha	638 MWh/ha	742 MWh/ha	237 MWh/ha	295 MWh/ha	700 MWh/ha
Distribution Piping											
Transmission Line (Trench Meters)	1,100 m	70 m	1,600 m	70 m	885 m	130 m	1,100 m	1,600 m	70 m	130 m	1,100 m
Transmission Line (Total Cost)	$2,145,000	$136,500	$3,488,000	$136,500	$1,575,300	$253,500	$2,145,000	$3,488,000	$152,600	$253,500	$2,816,000
Distribution Lines (Trench Meters)	580 m	750 m	1,685 m	1,780 m	280 m	1,105 m	2,180 m	3,040 m	3,305 m	1,135 m	4,500 m
Distribution Lines (Total Cost)	$1,131,000	$1,285,000	$3,309,950	$3,148,400	$470,400	$1,913,900	$4,179,600	$5,936,850	$6,247,650	$2,075,550	$9,039,200
Branch Lines (Trench Meters)	1,145 m	305 m	2,240 m	480 m	560 m	970 m	1,670 m	2,615 m	1,475 m	1,235 m	3,275 m
Branch Lines (Total Cost)	$1,850,250	$517,000	$3,598,500	$844,200	$920,100	$1,607,000	$2,730,350	$4,255,850	$2,490,950	$2,052,200	$5,304,800
DPS Subtotal	**$5,126,250**	**$1,938,500**	**$10,396,450**	**$4,129,100**	**$2,965,800**	**$3,774,400**	**$9,054,950**	**$13,680,700**	**$8,891,200**	**$4,381,250**	**$17,160,000**
Energy Transfer Stations											
# of Buildings Connected	14	4	31	6	5	8	19	35	14	9	50
Average ETS Cost per Building	$112,821	$228,250	$126,655	$199,250	$109,300	$139,688	$137,816	$139,086	$165,214	$147,500	$110,236
ETS Subtotal	**$1,579,500**	**$913,000**	**$3,926,300**	**$1,195,500**	**$546,500**	**$1,117,500**	**$2,618,500**	**$4,868,000**	**$2,313,000**	**$1,327,500**	**$5,511,800**
Plant											
Base Load - Alt Heating Module (Biomass)	$1,919,300	$1,576,900	$5,191,600	$1,958,800	$813,500	$1,835,000	$3,674,700	$6,809,100	$3,793,800	$2,251,500	$8,107,500
Peaking Boilers	$1,645,000	$1,351,500	$4,449,700	$1,678,800	$697,100	$1,572,600	$3,149,500	$5,836,000	$3,251,400	$1,929,600	$6,948,800
Plant Subtotal	**$3,564,300**	**$2,928,400**	**$9,641,300**	**$3,637,600**	**$1,510,600**	**$3,407,600**	**$6,824,200**	**$12,645,100**	**$7,045,200**	**$4,181,100**	**$15,056,300**
Total Cost of Capital	**$10,270,050**	**$5,779,900**	**$23,964,050**	**$8,962,200**	**$5,022,900**	**$8,299,500**	**$18,497,650**	**$31,193,800**	**$18,249,400**	**$9,889,850**	**$37,728,100**
Annualized Capital @ 25 yrs and 5.5% Interest	$766,000	$431,000	$1,787,000	$668,000	$374,000	$619,000	$1,379,000	$2,325,000	$1,360,000	$737,000	$2,813,000
Capital Reference $ per kW	$2,654 /kW	$1,818 /kW	$2,289 /kW	$2,269 /kW	$3,063 /kW	$2,243 /kW	$2,496 /kW	$2,272 /kW	$2,386 /kW	$2,178 /kW	$2,308 /kW
Total Revenue @ $185 /MWh	$1,654,344	$1,574,350	$4,316,666	$1,413,400	$493,950	$1,184,000	$3,367,056	$5,892,478	$2,597,400	$1,507,750	$7,104,809
Cost of Heating Energy Production											
Operations and Maintenance	$345,000	$301,000	$575,000	$338,000	$262,000	$328,000	$474,000	$692,000	$477,000	$356,000	$791,000
Furnace Oil Fuel Cost	$207,000	$197,000	$540,000	$177,000	$62,000	$148,000	$421,000	$737,000	$325,000	$189,000	$888,000
Biomass (25% Moisture) Fuel Cost	$343,000	$327,000	$896,000	$293,000	$103,000	$246,000	$699,000	$1,223,000	$539,000	$313,000	$1,475,000
Total Cost of Heating Energy Production	**$895,000**	**$825,000**	**$2,011,000**	**$808,000**	**$427,000**	**$722,000**	**$1,594,000**	**$2,652,000**	**$1,341,000**	**$858,000**	**$3,154,000**
Net Revenue	**$759,344**	**$749,350**	**$2,305,666**	**$605,400**	**$66,950**	**$462,000**	**$1,773,056**	**$3,240,478**	**$1,256,400**	**$649,750**	**$3,950,809**
Simplified Payback	**13.5 yrs**	**7.7 yrs**	**10.4 yrs**	**14.8 yrs**	**>50 yrs**	**18.0 yrs**	**10.4 yrs**	**9.6 yrs**	**14.5 yrs**	**15.2 yrs**	**9.5 yrs**

Notes:

1) Loads are as estimated from Loads and Energy Table previously provided.
2) Only loads greater than 100 kW and within distribution range were considered.
3) Remaining loads assumes a 100% market penetration.
4) All costs include material supply, mechanical installation, engineering and applicable taxes.
5) DPS cost is based on a pressure drop of 175 Pa/m and delta T of 40 deg C.
6) DPS Transmission and Distribution line sizing and cost are based on diversified loads (assumed to be 85% of contract load).
7) DPS Branch line sizing and costs is based on contract loads.
8) ETS Cost reflects an in-direct connection based on 120°C district heating supply temperature.
9) ETS sizing is based on contract loads.
10) Plant costs assume a biomass heated base load of 1/3 the total diversified load.
11) Peaking plant costs are assumed to be oil heated and based on a size of 100% total diversified load to incorporate redundancy.
12) Estimate provided is preliminary and is based on FVB sketches provided.
13) Cost is for preliminary screening only. Only to be used as a cost comparison.
14) Does not include the cost to purchase land.
15) Boiler operating conditions with a wood fuel temperature of 30.74 deg F, stack exit temperature of 560 deg F, excess air of 40% and a 1.5% conventional heat loss
16) Operating Costs assume: Furnace Oil @ $1 /litre @ 80% Seasonal Boiler Efficiency
    Biomass (25% Moisture) @ $150 per Green Tonne and 72.8% Energy Recovery Efficiency
    Electricity Costs $180 per MWh(e)

Appendix C - Alternative Energy Supply Screening

C.1 Assumed Zone Schematic

LEGEND:

ZONE 1:

1. F.H. Collins Secondary School
2. Selkirk Elementary School
6. Vanier Catholic Secondary School
7. Christ the King Elementary School
9. The Pine (31 Lewes)
11. Skyline Apartments
12. 93 Lewes Blvd (Block B)
13. 93 Lewes Blvd (Block A)
14. 1 Klondlike Road
15. Norman D. Macaulay Lodge
20. Peak Commercial
21. YEC Office
22. YEC Diesel Plant

ZONE 2:

1. Whitehorse General Hospital
2. Thomson Centre
5. #1 Hospital Road – Crocus Ridge
6. Education Building

ZONE 3:

1. Yukon Territory Government Admin Bldg
2. Whitehorse Visitor Information Centre
3. Closeleigh Manor
4. Edgewater Hotel
5. Horwood's Shopping Plaza
6. City Hall / Fire Hall
7. Canada's Best Value Inn
10. Pro Log Project Logistics
11. Financial Plaza
15. Westmark Hotel & Conf. Centre
16. Law Courts (Yukon Justice Building)
17. 202 Motor Inn
21. High Country Inn
22. 3090 Lambert St.
25. Elijah Smith
26. Lynn Building
27. Prospector Place
28. Residential at Strickland st. and 4th ave
29. Whitehorse Elementary
39. RCMP Building (to be renovated in future)
40. Town & Mountain Hotel
41. Best Western Gold Rush Inn
42. RBC Royal Bank
44. Wood Street Centre
45. Stratford Motel

REVISIONS		
DATE	REMARKS	NO.

City of Whitehorse
ENGINEERING

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: **WHITEHORSE**

SHEET TITLE: –

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAR 06/2012

DWG NO.: SK–1313–002

C.2 Energy Screening Memo

Alternative Energy Supply Screening

for

YUKON ENERGY CORPORATION

Matthew Sills
Procurement Department
2 Miles Canyon Rd.
Whitehorse, YT Y1A 6S7

Prepared by:

FVB ENERGY INC

Suite 350, 13220 St Albert Trail NW
Edmonton, AB T5L 4W1

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1 General Intent

The general intent of this document is to compare alternatives to supply the baseload energy supply options for the proposed Whitehorse Community Energy system. The results of this screening will help in the selection of the preferred energy supply solution(s).

This screening uses order of magnitude capital estimates for the energy supply options plus indicative equipment efficiencies for the screening inputs. The inputs do not include any costs associated with the distribution piping network, nor the energy transfer station connections within the customer buildings.

Once the preferred energy supply option has been selected a more detailed technical concept will be developed including capital and operating estimates with a higher degree of confidence for the energy centre(s), distribution piping, and energy transfer stations. It will be these more detailed estimates that will be used as inputs to the business model.

2 Heating Load and Energy

For the purposes of the screening analysis, the community energy system was sized to meet the space heating and domestic hot water loads for the Hospital Road, Riverdale and downtown core.

Please refer to the Mid-Project Review Package for more details on Scenario #11, which is the basis for all subsequent technical concept work.

For the purposes of the energy screening analysis, the full build-out load of the preferred community energy case is used to evaluate and compare resource options. The diversified loads[1] assumed for the purposes of the screening analysis are summarized below in Table 1.

Table 1 - Summary of Diversified Load Assumptions

	Total Peak
Diversified Peak [MW]	13.9
Annual Energy [MWh]	38,400
Equivalent Full Load Duration[2]	2,764 hrs

[1] Diversification of load is an inherent benefit of community energy systems over conventional in-building systems, particularly when serving mixed-use buildings. The differing building types, occupancies and uses result in non-coincidental peaks. FVB Energy has extensive knowledge in this area. For this development, a heating diversification of 0.85 is used.

[2] Equivalent Full Load Duration is the number of equivalent hours at full demand the building would use to get the same annual energy use. It is used to compare different building types and occupancies.

2.1 Heating Load Duration Curve

The figure below is representative of the heating demand for the community energy system through the year. The load duration curve is the starting point for sizing the required capacity to satisfy the total thermal load. The area under the curve represents the annual energy.

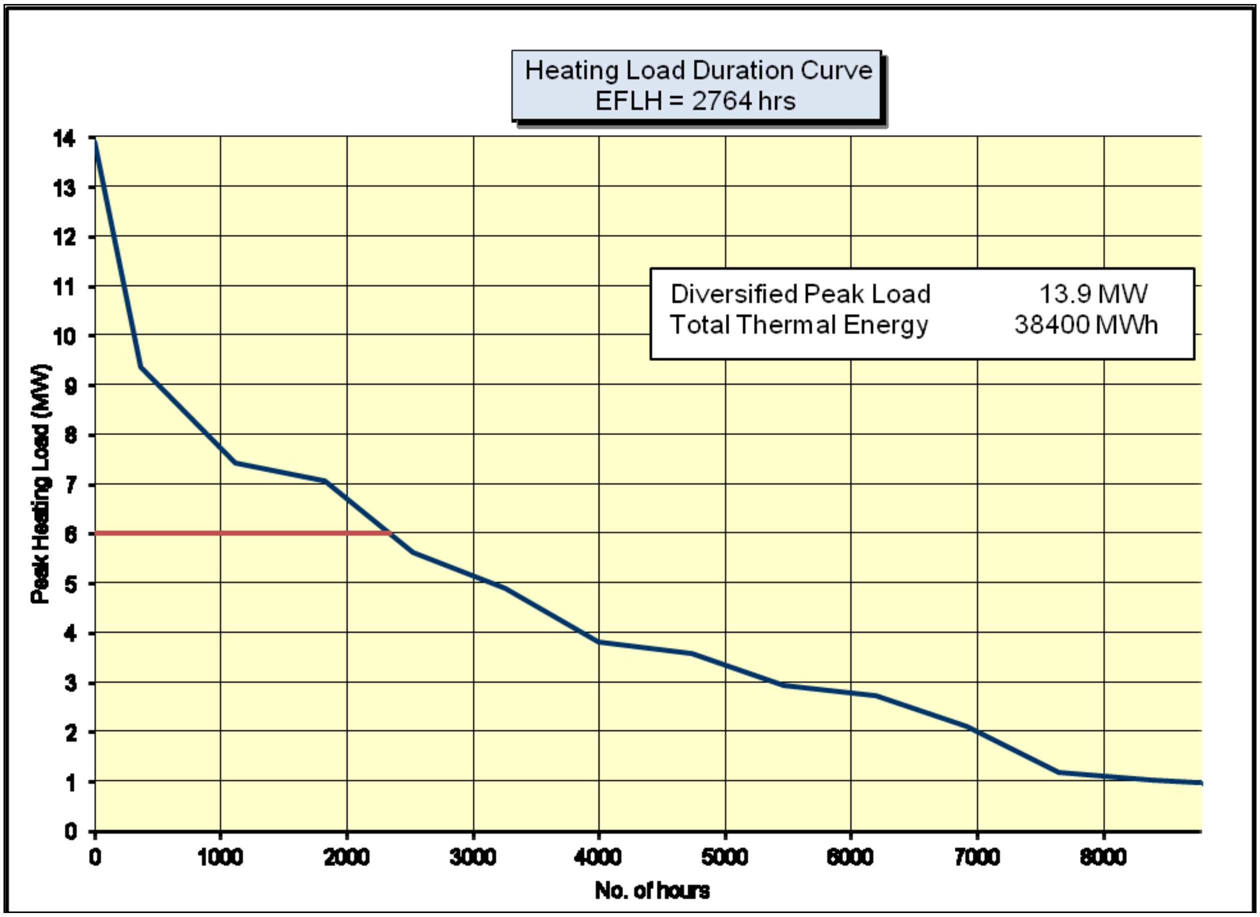


Figure 1 - Heating Load Duration Curve

The load duration curve is a representation of the hours a particular demand is present. For example, for heating, the design peak is at "zero" hours, meaning it happens for a very short time. Whereas, the heating demand is greater than 6 MW_{th}'s (as shown above by the red line) for 2,340 hours.

The load duration curve is also used to size the alternate energy capacity, which are capital intensive, but use relatively low cost fuel.

For the energy screening, it was assumed that 6.0 MW_{th} capacity is provided by alternative heat capacity. The scenarios are run to provide the maximum amount of thermal energy from the alternative heat provided.

3 Community Energy Technical Concept

The recommended technical concept incorporates the use of three heating plant locations to minimize the capital spent at start-up and maximize the system redundancy and operating flexibility.

1. Plant #1 - Whitehorse General Hospital
   a. One 4.0 MW_{th} existing boiler – fuel oil
2. Plant #2 – YEC Plant Site
   a. Two 3.5 MW_{th} boilers – natural gas
   b. Alternative Capacity - 6.0 MW_{th} with varying fuel sources
3. Plant #3 – Downtown core
   a. One 3.5 MW_{th} boiler – fuel oil

For more details, please refer to Appendix A – Community Energy Concept Schematic.

4 Alternative Energy Plant Options

Based on the information assembled, the community energy screening analysis undertaken, and the subsequent meetings with the Study Team and YEC, FVB reviewed eight alternative energy supply options for the baseload thermal energy supply. At the request of YEC we have assumed the liquefied natural gas will be available as a primary fuel supply at the YEC location. If this assumption does not come to fruition the boilers can be easily switched to fuel oil. The energy supply Alternatives screened include:

1. Boilers – Liquefied Natural Gas
2. Biomass Boiler - Wood Chip Fuel
3. Biomass Boiler - Wood Pellet Fuel
4. Biomass Boiler with Combined Organic Rankine Cycle - Wood Chip Fuel
5. Biomass Boiler with Combined Organic Rankine Cycle - Wood Pellet Fuel
6. Reciprocating Engine Cogeneration – Liquefied Natural Gas
7. Reciprocating Engine Cogeneration – Fuel Oil
8. Heat Recovery on Existing Generators – Fuel Oil

Also included in this package are:

- The load duration curves used in equipment sizing, calculating the energy provided and fuel usage can be found in Appendix B.
- The energy screening detailed results can be found in Appendix C, based on general assumptions and an assumed electrical sales price of $150 / MWh_e.
- Appendix D shows the energy screening detailed results, based on general assumptions, but assuming an electrical sales price of $200 / MWh_e.
- Schematics showing typical installation configurations for the alternative options are shown in Appendix E.

4.1 General Assumptions

There are some assumptions that stay consistent for each alternative; these are:

1. Diversified heating demand: 13.9 MW_{th}
2. Annual thermal Energy: 38,400 MWh_{th}
3. Peaking and Back-up Boilers (LNG):
    a. YEC (P2) Capacity 2 @ 3.5 MW_{th}
    b. Fuel LNG
        i. Fuel Higher Heating Value (HHV) 10.5 kWh/m^3 37.8 MJ/m^3
        ii. Fuel Cost: $15.00 / GJ
        iii. Additional heat required to vapourize LNG 1.5%
        iv. Seasonal Boiler efficiency: 80%
        v. Base Staffing Requirements: 2 FTE
4. Peaking and Back-up Boilers (Fuel Oil):
    a. Hospital (P1) Capacity 4.0 MW_{th}
    b. Downtown Energy Centre (P3) Capacity: 3.5 MW_{th}
    c. Fuel – Fuel Oil #2 Oil
        i. Fuel Higher Heating Value (HHV) 10.81 kWh/L 38.91 MJ/Litre
        ii. Fuel Cost: $1.00 / Litre
        iii. Seasonal Boiler efficiency: 80%
        iv. Base Staffing Requirements: No additional
5. Electricity
    a. Purchase price: $145.7 /$MWh_e$
    b. Sale price for Analysis #1: $150.0 /$MWh_e$
    c. Sale Price for Analysis #2: $200.0 /$MWh_e$
6. Annualized Capital
    a. Amortization period 25 Years
    b. Interest rate: 6.2%
7. GHG Calculations
    a. Fuel CO_2 equivalent tonnage does not include transportation
    b. GHG Equivalent Intensities
        i. Wood products are assumed to have equivalent greenhouse gas emissions whether burned or left to naturally decay, GHG neutral.
        ii. Natural Gas 50 kg/GJ
        iii. Fuel Oil #2 69 kg/GJ
        iv. Electricity (Existing Oil Fired) 773 kg/MWh_e
    c. Business as Usual Case – used to calculate base GHG emissions
        i. Fuel: #2 Oil
        ii. Seasonal Boiler efficiency: 65%
        iii. Existing electrical production efficiency: 3.7 kWh_e/L
        iv. Existing electrical production efficiency (LHV): 36%

4.2 Alternative #1 - Community Energy with LNG Boilers

This alternative assumes a community energy system with 13.0 MW_{th} of baseload boiler capacity fueled by liquefied natural gas. The following assumptions are used:

1. Boilers
   a. Downtown — 1 Blr @ 3.5 MW_{th} – Fuel Oil
   b. Hospital — 1 Blr @ 4.0 MW_{th} – Fuel Oil
   c. YEC — 13.0 MW_{th} – LNG
2. Seasonal Boiler efficiency: 80%
3. Base Staffing Requirements: 2 FTE

4.3 Alternative #2 - Biomass Boiler with Woodchips as Fuel Source

This alternative assumes a community energy system with 6.0 MW_t of baseload boiler capacity fueled by wood chips in a biomass boiler. The following assumptions are used:

1. Alternative Fuel Source
   a. Fuel is assumed to be burner ready (no additional conversion costs).
   b. Cost: $150 /Green tonne
   c. Moisture content 25%
   d. Higher heating value: 20.6 MJ/kg
   e. Ash content: 3%
   f. Ash removal: $40 / tonne
2. Biomass boilers:
   a. Boilers: 2 @ 3.0 MW_{th}
   b. Seasonal boiler efficiency (HHV): 75%
   c. Turndown: 33%
   d. Incremental Staff 1 FTE

4.4 Alternative #3 - Biomass Boiler with Pellets as Fuel Source

This alternative assumes a community energy system with 6.0 MW_t of baseload boiler capacity fueled by wood pellets in a biomass boiler. The following assumptions are used:

1. Alternative Fuel Source
   a. Fuel is assumed to be burner ready (no additional conversion costs).
   b. Cost: $326 /Green tonne
   c. Moisture content 7%
   d. Higher heating value: 20.6 MJ/kg
   e. Ash content: 1%
   f. Ash removal: $40 / tonne
2. Biomass boilers:
   a. Boilers: 2 @ 3.0 MW_{th}
   b. Seasonal boiler efficienc$_y$ (HHV): 78%
   c. Turndown: 33%
   d. Incremental Staff 1 FTE

4.5 Alternative #4 - Biomass Boiler with Organic Rankine Cycle – Wood Chips

This alternative assumes a community energy system with a baseload biomass boiler fueled by wood chips, coupled with an organic Rankine cycle (ORC) that produces both electricity and thermal energy. The ORC system was sized to provide 6.0 MW_{th} of thermal capacity to the community energy system. The following assumptions are used:

1. Alternative Fuel Source
    a. Fuel is assumed to be burner ready (no additional conversion costs).
    b. Cost: $150 /Green tonne
    c. Moisture content 25%
    d. Higher heating value: 20.6 MJ/kg
    e. Ash content: 3%
    f. Ash removal: $40 / tonne
2. Biomass boilers:
    a. Boilers: 2 @ 3.7 MW_{th}
    b. Seasonal boiler efficiency (HHV) 72%
    c. Turndown: 33%
    d. Incremental Staff 1 FTE
3. Organic Rankine Cycle (ORC)
    a. Net Electrical Output: 1,240 kW_e
    b. Annual Electrical Output: 6,840 MWh_e
    c. Electrical efficiency 16.8%
4. Assumed to be thermal load following; amount of electricity produced is limited by thermal requirements.

4.6 Alternative #5 - Biomass Boiler with Organic Rankine Cycle – Wood Pellets

This alternative assumes a community energy system with a baseload biomass boiler fueled by wood chips, coupled with an organic Rankine cycle (ORC) that produces both electricity and thermal energy. The ORC system was sized to provide 6.0 MW_{th} of thermal capacity to the community energy system. The following assumptions are used:

1. Alternative Fuel Source
    a. Fuel is assumed to be burner ready (no additional conversion costs).
    b. Cost: $326 /Green tonne
    c. Moisture content 7%
    d. Higher heating value: 20.6 MJ/kg
    e. Ash content: 1%
    f. Ash removal: $40 / tonne
2. Biomass boilers:
    a. Boilers: 2 @ 3.7 MW_{th}
    b. Seasonal boiler efficiency (HHV): 75%
    c. Turndown: 33%
    d. Incremental Staff 1 FTE

3. Organic Rankine Cycle (ORC)
    a. Net Electrical Output: 1,240 kW_e
    b. Annual Electrical Output: 6,840 MWh_e
    c. Electrical efficiency 16.8%
4. Assumed to be thermal load following. Amount of electricity produced is limited by thermal requirements.

4.7 Alternative #6 - Reciprocating Engine Cogeneration – Natural Gas

This alternative assumes the installation of natural gas driven reciprocating engine electrical generators with heat recovery sized at 6.0 MW_{th} to supply baseload thermal energy to the community energy system. The following assumptions are used:

1. Alternative Fuel Source
    a. Fuel: Liquefied Natural Gas
    b. Fuel Higher Heating Value (HHV) 37.8 MJ/m^3
    c. Fuel Cost: $15.00 / GJ
    d. Fuel is assumed to be burner ready (no additional conversion or storage costs).
2. Reciprocating Engines:
    a. Net Electrical Output: 6,000 kW_e
    b. Annual Electrical Output: 29,360 MWh_e
    c. Annual Run Hours: 4,890 hours
    d. Electrical efficiency (LHV) 38%
    e. Engine O&M Costs: $12 / MWh_e
    f. Waste Heat Recovery; 6,000 kW_{th}
    g. Incremental Staff 1 FTE
3. Assumed to be full electrical output for all run hours with heat not recovered for community energy to be dumped using radiators.

4.8 Alternative #7 - Reciprocating Engine Cogeneration – Fuel Oil

This alternative assumes the installation of new fuel oil driven reciprocating engine electrical generators with heat recovery sized at 6.0 MW_{th} to supply baseload thermal energy to the community energy system. The following assumptions are used:

1. Alternative Fuel Source
    a. Fuel: #2 Fuel Oil
    b. Fuel Higher Heating Value (HHV) 10.81 kWh/L
       38.91 MJ/Litre
    c. Fuel Cost: $1.00 / Litre
    d. Fuel is assumed to be burner ready (no additional conversion or storage costs)
2. Reciprocating Engines:
    a. Net Electrical Output: 6,000 kW_e
    b. Annual Electrical Output: 29,360 MWh_e

   c. Annual Run Hours: 4,890 hours
   d. Electrical efficiency (LHV) 40%
   e. Engine O&M Costs: $12 / MWh$_e$
   f. Waste Heat Recovery: 6,000 kW$_{th}$
   g. Incremental Staff 1 FTE
3. Assumed to be full electrical output for all run hours with heat not recovered for community energy to be dumped using radiators.

4.9 Alternative #8 - Heat Recovery on Existing Generators

This alternative assumes the installation of heat recovery equipment on existing fuel oil driven reciprocating engine electrical generators. The additional equipment is sized to 6.0 MW$_{th}$ to supply baseload thermal energy to the community energy system. The following assumptions are used:

1. Alternative Fuel Source
   a. Fuel: #2 Fuel Oil
   b. Fuel Higher Heating Value (HHV) 10.81 kWh/L
      38.91 MJ/Litre
   c. Fuel Cost: $1.00 / Litre
   d. Fuel is assumed to be burner ready (no additional conversion or storage costs).
2. Reciprocating Engines:
   a. Net Electrical Output: 6,000 kW$_e$
   b. Annual Electrical Output: 29,360 MWh$_e$
   c. Annual Run Hours: 4,890 hours
   d. Electrical efficiency (LHV) 36%
   e. Engine O&M Costs: $12 / MWh$_e$
   f. Waste Heat Recovery; 6,000 kW$_{th}$
   g. Incremental Staff 1 FTE
3. Assumed to be full electrical output for all run hours with heat not recovered for community energy to be dumped using radiators.

5 Results

This section summarizes the key results of the energy screening calculations. This includes:

1) The total energy centre capital required for the alternative baseload heating capacity installed.
2) The Greenhouse Gas emission reductions over the business as usual for each alternative. Business as usual assumes that the thermal energy for the buildings would be continued to be produced using oil boilers at a seasonal boiler efficiency of 65% and electricity would be required to be produced using the existing oil fire generation capacity.

3) The annualized cost of alternative heat energy per megawatt-hour of thermal energy provided to the community energy system.
4) The total annualized cost of the alternative baseload, peaking and back-up heating per unit of thermal energy provided to the community energy system.

The key results are provided in Table 3. A more detailed summary is provided in Appendix C.

Table 2 - Key Energy Screening Results

	Alternative #1 **Standard Boilers** ***LNG***	**Alternative #2** **Biomass Boilers** ***Wood Chips***	**Alternative #3** **Biomass Boilers** ***Wood Pellets***	**Alternative #4** **Biomass Boiler with ORC** ***Wood Chips***
Alternative Energy Centre Capital	N/A	$10,500,000	$10,500,000	$15,320,000
GHG Reductions over BAU (CO_2 eq)	5,950 Tonnes	13,100 Tonnes	13,100 Tonnes	18,240 Tonnes
Alternative Energy Cost of Thermal Energy	N/A	\$ 85 / MWh_{th}	\$ 116 / MWh_{th}	\$ 79 / MWh_{th}
Total Blended Cost of Thermal Energy	\$ 99 / MWh_{th}	\$ 104 / MWh_{th}	\$ 131 / MWh_{th}	\$ 99 / MWh_{th}

	Alternative #5 **Biomass Boiler with ORC** ***Wood Pellets***	**Alternative #6** **Reciprocating Engine Cogeneration** ***LNG***	**Alternative #7** **Reciprocating Engine Cogeneration** ***Fuel Oil***	**Alternative #8** **Heat Recovery on Existing Generators** ***Fuel Oil***
Alternative Energy Centre Capital	$15,320,000	$15,000,000	$13,500,000	$2,400,000
GHG Reductions over BAU (CO_2 eq)	18,240 Tonnes	17,720 Tonnes	13,770 Tonnes	11,830 Tonnes
Alternative Energy Cost of Thermal Energy	\$ 117 / MWh_{th}	\$ 83 / MWh_{th}	\$ 177 / MWh_{th}	\$ 171 / MWh_{th}
Total Blended Cost of Thermal Energy	\$ 131 / MWh_{th}	\$ 100 / MWh_{th}	\$ 163 / MWh_{th}	\$ 159 / MWh_{th}

The scenario was also evaluated using a electricity sales price of \$200 / MWh_e. The key results are provided in Table 4, with a more detailed summary provided in Appendix D.

Table 3 - Energy Screening Results Comparison using Varied Electricity Sales Prices

	Alternative #1 **Standard Boilers** ***LNG***	**Alternative #2** **Biomass Boilers** ***Wood Chips***	**Alternative #3** **Biomass Boilers** ***Wood Pellets***	**Alternative #4** **Biomass Boiler with ORC** ***Wood Chips***
Total Blended Cost of Thermal Energy				
Electricity Sale Price @ \$150 /MWh_e	\$ 99 / MWh_{th}	\$ 104 / MWh_{th}	\$ 131 / MWh_{th}	\$ 99 / MWh_{th}
Electricity Sale Price @ \$200 /MWh_e	\$ 99 / MWh_{th}	\$ 104 / MWh_{th}	\$ 131 / MWh_{th}	\$ 90 / MWh_{th}

	Alternative #5 **Biomass Boiler with ORC** ***Wood Pellets***	**Alternative #6** **Reciprocating Engine Cogeneration** ***LNG***	**Alternative #7** **Reciprocating Engine Cogeneration** ***Fuel Oil***	**Alternative #8** **Heat Recovery on Existing Generators** ***Fuel Oil***
Total Blended Cost of Thermal Energy				
Electricity Sale Price @ \$150 /MWh_e	\$ 131 / MWh_{th}	\$ 100 / MWh_{th}	\$ 163 / MWh_{th}	\$ 159 / MWh_{th}
Electricity Sale Price @ \$200 /MWh_e	\$ 122 / MWh_{th}	\$ 61 / MWh_{th}	\$ 125 / MWh_{th}	\$ 121 / MWh_{th}

5.1 Reliability

The community energy system will be designed to supply Whitehorse with a utility grade supply of thermal energy. At full build-out, if the largest unit unexpectantly shuts down, the system has enough back-up capacity installed to provide full capacity to its customers at full rates. The community energy system will have three energy centres with a minimum of two fuel sources (Alternatives 1 thru 6).

5.2 Affordability

From the above results, one of the largest factors in the annualized cost is the fuel costs.

Table 4 - Fuel Source Comparison

Fuel Type	Fuel Source	Cost per Volume	Cost per Energy Content
Liquefied Natural Gas	Edmonton	$ 0.567 / m^3	$ 15.00 / GJ
Fuel Oil	Edmonton	$ 1.00 / Litre	$ 25.70 / GJ
Wood Chips	Local Burn Site	$ 150 / Green Tonne	$ 9.71 / GJ
Wood Pellets	Burns Lake	$326 / Tonne	$ 17.02 / GJ

We have calculated the total cost of the supplied thermal energy as summarized below:

Table 5 - Cost of Delivered Thermal Energy

Alternative	Total Blended Cost of Thermal Energy
Alt #1 - LNG Boilers	$ 99 / MWh
Alt #2 - Biomass Boilers - Wood Chips	$ 104 / MWh
Alt #3 - Biomass Boilers - Wood Pellets	$ 131 / MWh
Alt #6 - Recip Cogen on LNG	$ 100 / MWh

Note: As aforementioned, this is not reflective of the market rate of thermal energy. The inputs do not include any costs associated with the distribution piping network, nor the energy transfer station connections within the customer buildings.

The future commodity prices for Liquefied Natural Gas are uncertain. With natural gas at a 10 year low and the potential for strong international demand, the cost of LNG is assumed to increase.

Fuel oil comes from Edmonton and is trucked to Whitehorse. This fuel source is the highest priced energy source.

Wood chips come are assumed to come from local forest fire burn sites. An average price is assumed at $150 per green tonne delivered. However, the proposed system has a biomass tonnage requirement that would allow sourcing all of the wood chips from the Fox Lake site. This would significantly reduce the delivered fuel rate; approximated at $115.87 / green tonne or $7.50 / GJ, as per the Morrison Hershfield Biomass Energy Evaluation. Whatever source is selected, wood chips represent a low cost, highly dependable and locally supplied fuel source.

Wood pellet pricing is based on quotes offered by the Stantec report at $326 per tonne. The price is quoted from a local company, however previous work have received significantly lower quotes. The benefit of pelletizing wood is to reduce the hauling costs by removing the water content of the wood and creating compressed packages that allow for more wood to be hauled per load. The hauling distances for viable supplies of low moisture content wood chips are short; therefore this advantage of wood pellets isn't as relevant.

In general, the energy screening alternatives that are sourced by fuel oil or wood pellets are not as cost effective as those sourced by liquefied natural gas or wood chips. The LNG cogeneration option is attractive; however this cost is dramatically affected by the electrical sales cost and base commodity price, both of which will be affected by outside sources.

5.3 Flexibility

Inherently, community energy systems are flexible systems. The capital is built into the infrastructure required to supply heat to the customers. The energy heat source can be changed if a more attractive business model presents itself in the future.

The LNG cogeneration units lend themselves to burn any methane source of fuel. This could include biogas or syn gas provided locally from biomass or waste streams.

The biomass options can accept fuel from many biomass sources. This could include properly converted mill residue streams, waste from construction, renovation and demolition waste streams.

5.4 Environmental Responsibility

In general, some of the primary advantages of a community energy system are to create a central heat source that allows for energy efficiencies, flexible fuel supply options and emission controls that are not fiscally feasible with multiple smaller systems. In this respect, all alternatives have a positive impact over the status quo: Distributed oil boilers with electricity generated using oil-fired reciprocating engines.

The largest greenhouse gas emissions savings are seen with the electricity producing biomass options (Alt #4 & Alt #5) and LNG cogeneration (Alt #6). However, the environmental cost of transporting these fuels is not included in these calculations, which would further penalize petroleum sourced fuels.

5.5 *Qualitative Ranking Summary*

As per the Yukon Energy Charrette, the key energy planning principles were quantified and summarized below.

Table 6 - Qualitative Ranking for Alternatives

Criteria	Alt #1	Alt #2	Alt #3	Alt #4	Alt #5	Alt #6	Alt #7	Alt #8
Reliability	4	4	5	4	4	4	4	2
Affordability	4	4	2	4	2	5	1	1
Flexibility	3	4	3	5	4	3	3	2
Environmental Responsibility	2	4	4	5	5	4	2	1
Rank	6	3	5	1	4	2	7	8

6 Conclusion

1. The results of the energy screening as shown in Table 2 do not produce a clear winner for the alternatives reviewed.

2. Based on our screening analysis and the provided price of fuel, the production of electricity does not improve the community energy thermal price at an electrical price of \$150 / MWh_e.

3. If natural gas is available, it would be a good means of providing alternative energy capacity to a community energy system that could reduce the community's greenhouse gas emissions. At \$15 / GJ (provided by YEC) it would be a cheaper fuel alternative than fuel oil at \$26 / GJ (\$1/Litre).

4. The results do indicate that the alternatives using oil fired reciprocating engines (Alt#7 & Alt #8) do not produce viable alternatives at a fuel cost of \$1/Litre and an electricity price of \$150/MWh_e. When the price of electricity is increased to \$200/MWh_e Alt #7 & Alt #8 (see Table 3) maybe become viable alternatives but they are still less attractive than other alternatives.

5. The Biomass with ORC options (Alt #4 & Alt #5) assume that the electrical generation is small enough that the electrical grid can absorb the additional electricity generation and district heat can be supplied year-round. The cogeneration options (Alt #6, Alt #7 & Alt #8) assume that these units only run when electrical demand is high enough to warrant running the units. This screening assumes a run-time of 4,890 hours, however this may not reflect actual demand and is another externality that strongly affects the annualized cost of thermal energy.

6. Woodchip biomass or reciprocating engine cogeneration using natural gas produce similar prices of thermal energy and GHG reductions.

7. Woodchip biomass at $150 / tonne (Alt #2) is an attractive, locally supplied option for the community. Adding ORC to this option (Alt #4) has a significant positive impact on GHG reductions but has a marginal impact on thermal energy cost if electricity sales are at $150/MWh$_e$. In order to make ORC electrical production more viable a higher price of electricity is required. Increasing the electricity sale price from $150 to $200 / MWh$_e$ lowered the thermal cost of production for this solution from $99 to $90 / MWh$_{th}$. This could then justify the increased capital cost associated with adding electrical production.

8. Wood pellets are a much better solution than the existing fuel oil alternatives when it comes to GHG emissions but their high cost ($326 / tonne) compared to wood chips makes them a less viable alternative.

9. The screening analysis assumes a relatively high capital cost ($2,500 / kW$_e$) for the reciprocating engine capacity of 6 MW$_e$ for Alt #6. If YEC develops a much larger electrical generation plant (>than 24 MW$_e$) than the capital cost could come down significantly and thus potentially reduce the cost of thermal energy to the community energy system.

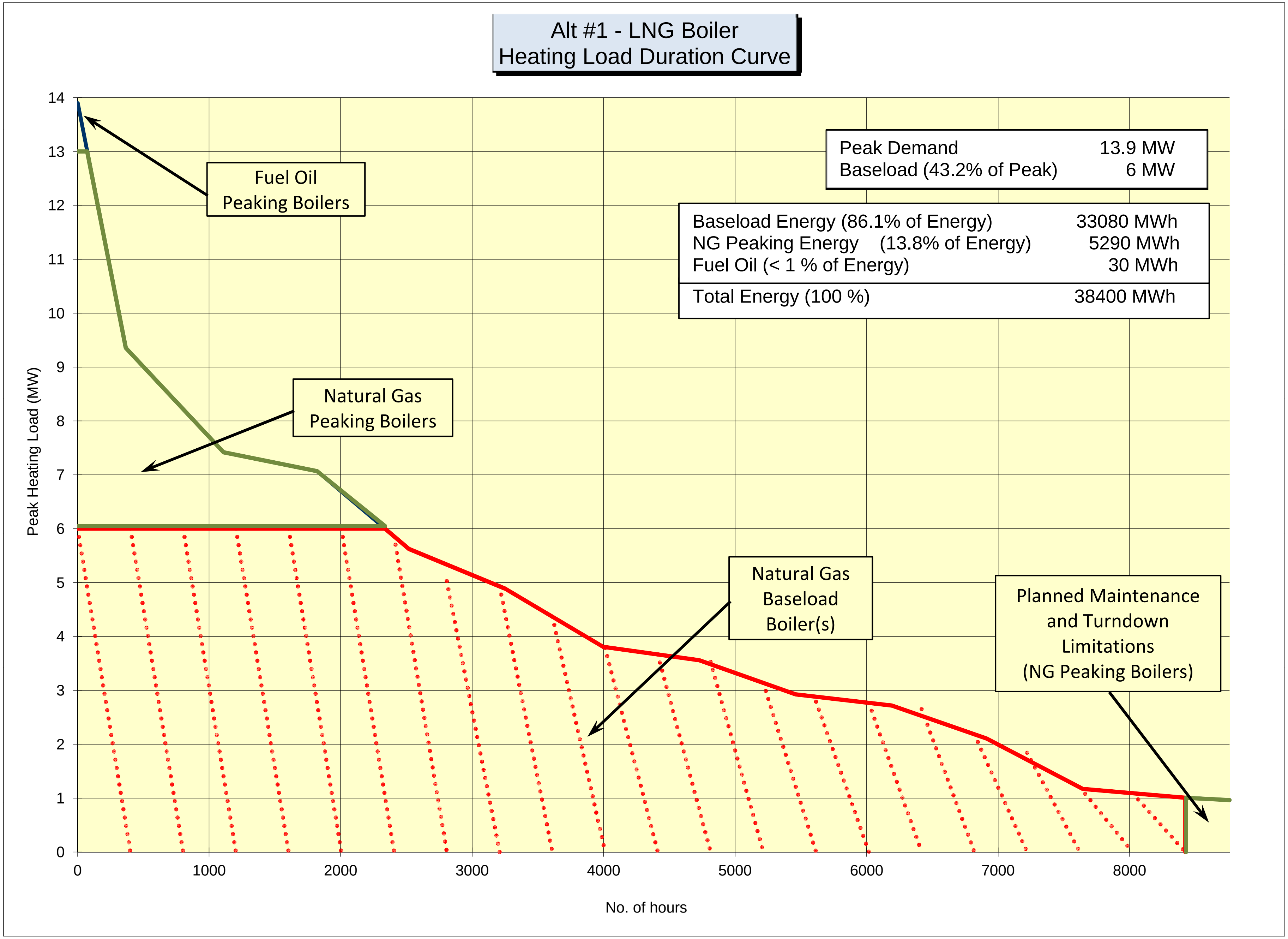
7 Recommendations

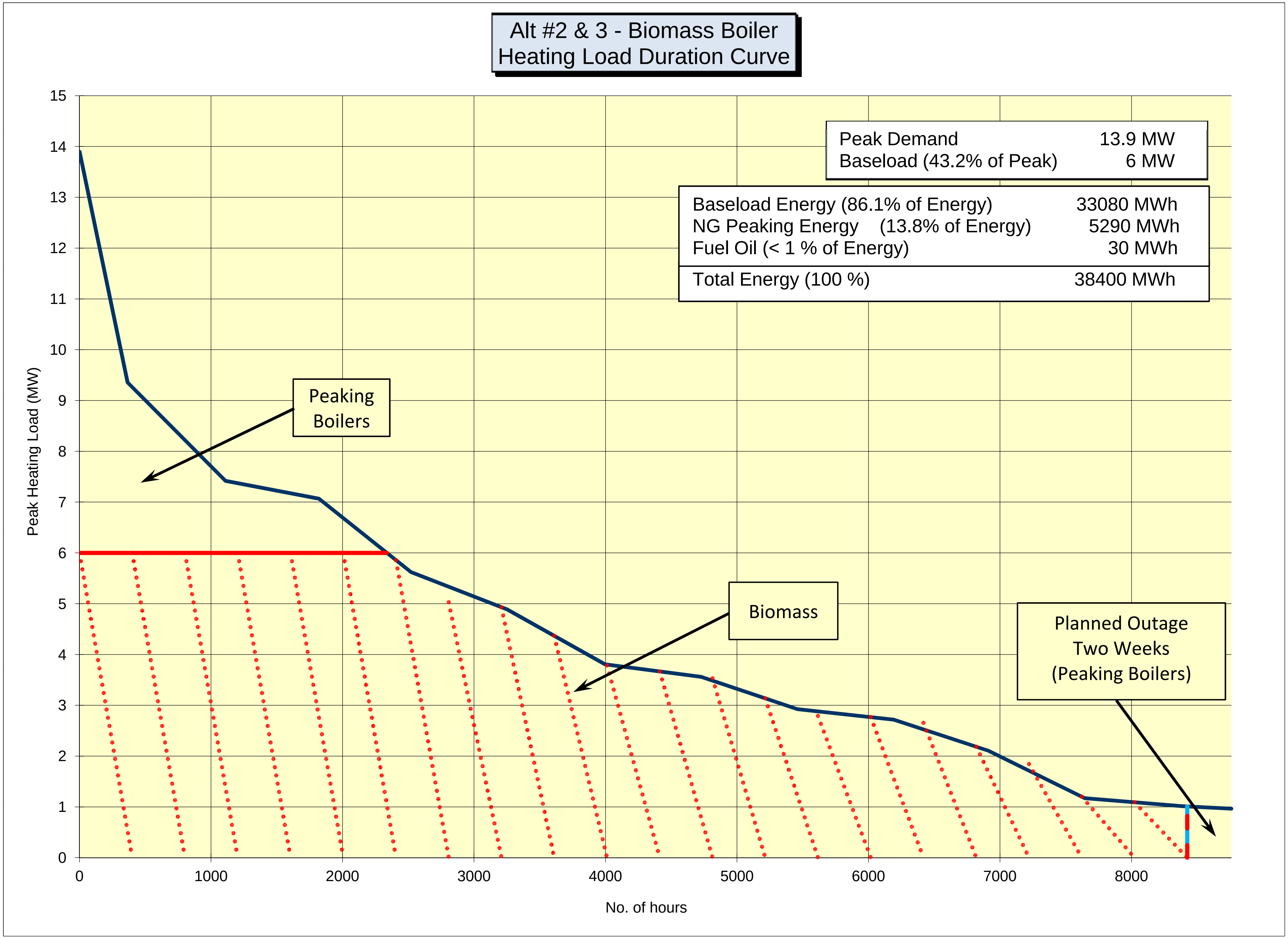
The LNG alternatives (Alt #1 & Alt #6) are dependent on factors outside the scope of this study. If it makes economic sense to bring LNG into the community to generate power, then it could be used as a fuel source for a community energy system that could be competitive with wood waste. The amount of power that would be optimally produced (thermal load following) using wood waste for a community energy system would not produce sufficient electricity to supplement the YEC projected electrical shortfall.

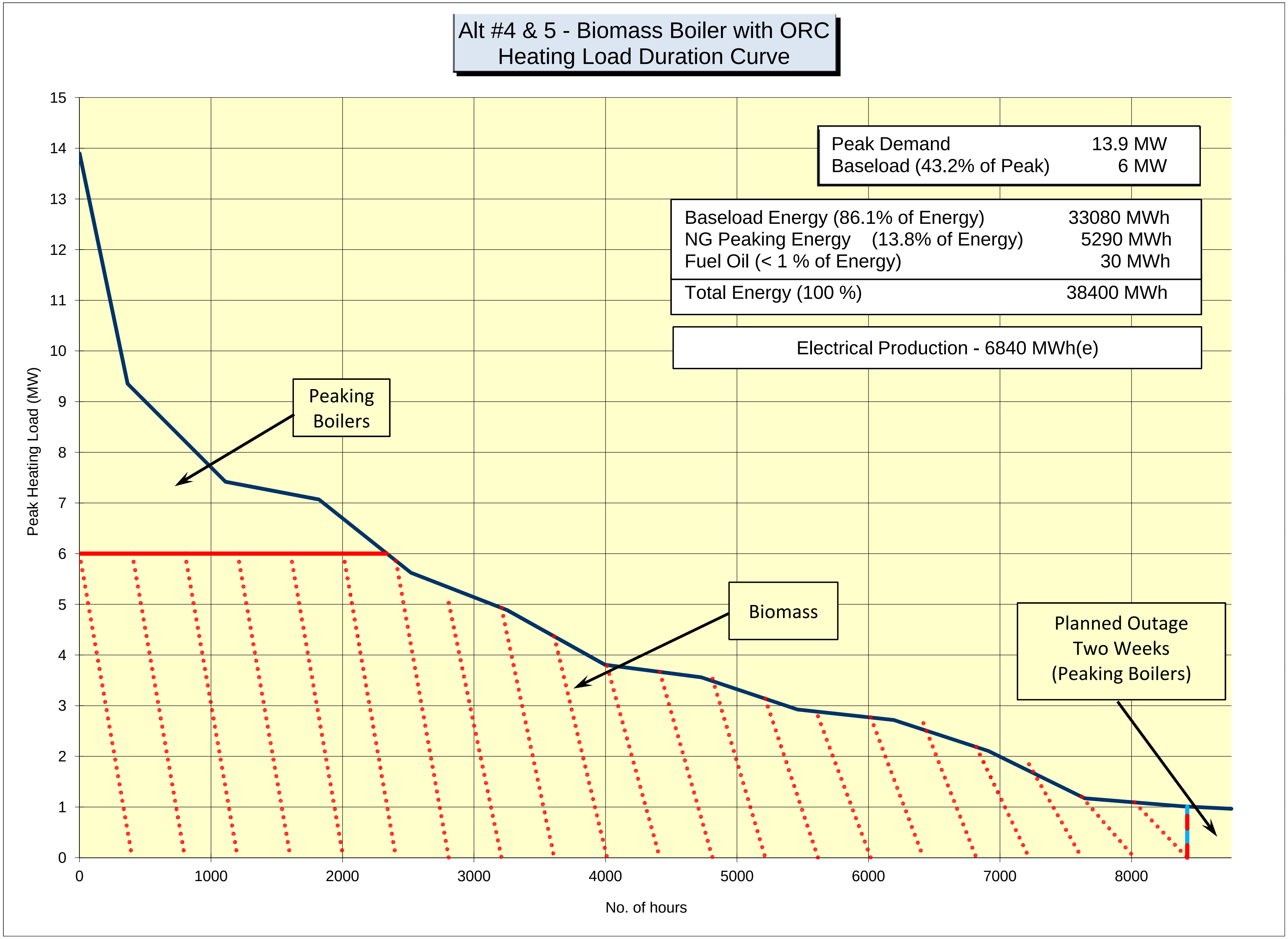
If one alternative is to be pursued for the community energy system we recommend the effort be spent on a biomass based system with ORC (Alt# 4). Our reasoning is that work is being completed by others to solve the projected electrical shortfall using LNG and that if this option develops it will benefit a community energy system. We recommend this scope of work focus on a biomass alternative which could produce thermal energy at a competitive price to waste heat from reciprocating engine cogeneration.

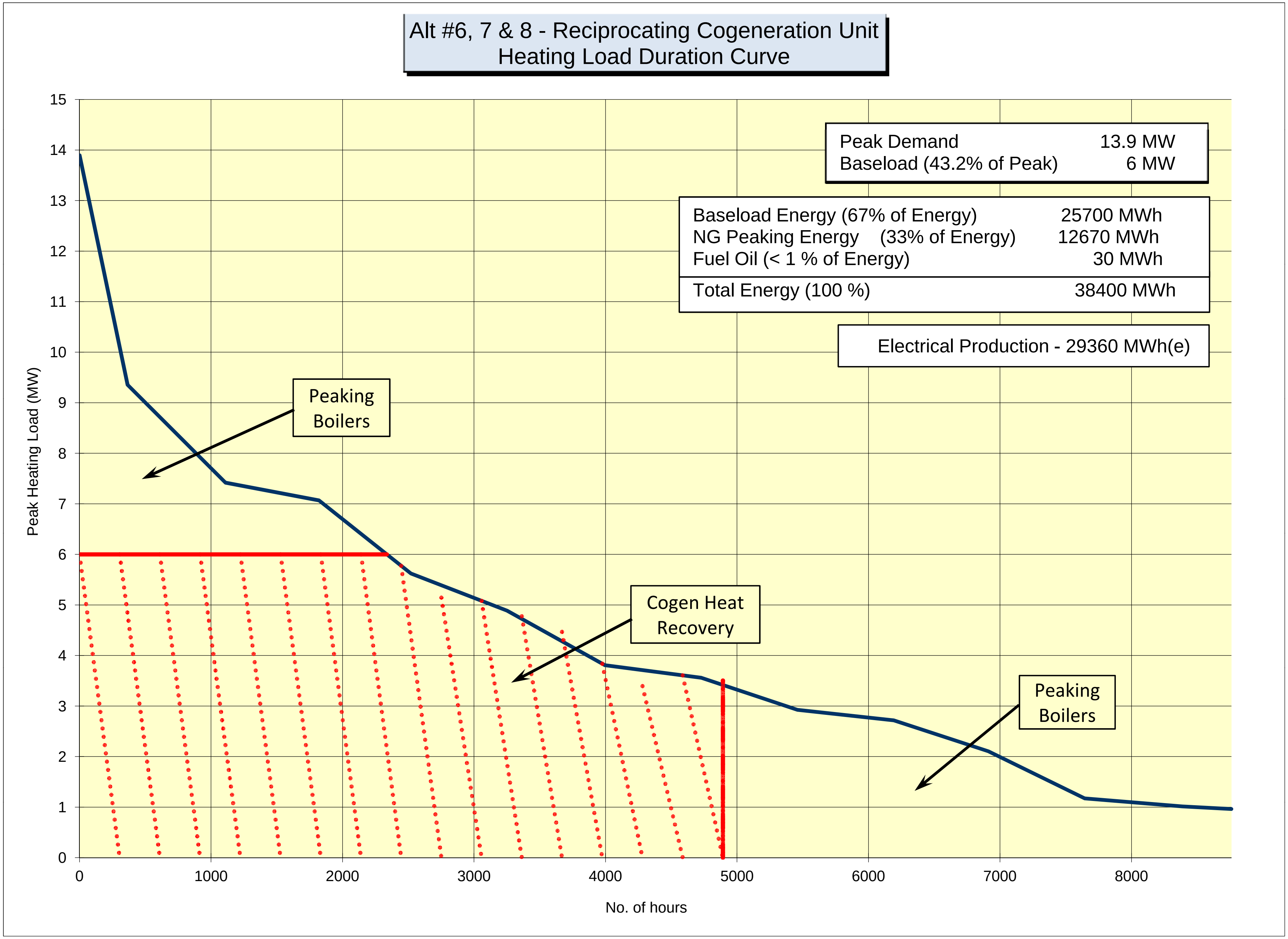
**** End ****

C.3 Load Duration Curves


Alt #1 - LNG Boiler
Heating Load Duration Curve
Peak Demand 13.9 MW
Baseload (43.2% of Peak) 6 MW
Baseload Energy (86.1% of Energy) 33080 MWh
NG Peaking Energy (13.8% of Energy) 5290 MWh
Fuel Oil (< 1 % of Energy) 30 MWh
Total Energy (100 %) 38400 MWh
Fuel Oil Peaking Boilers
Natural Gas Peaking Boilers
Natural Gas Baseload Boiler(s)
Planned Maintenance and Turndown Limitations (NG Peaking Boilers)
Peak Heating Load (MW)
No. of hours
0
1000
2000
3000
4000
5000
6000
7000
8000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14

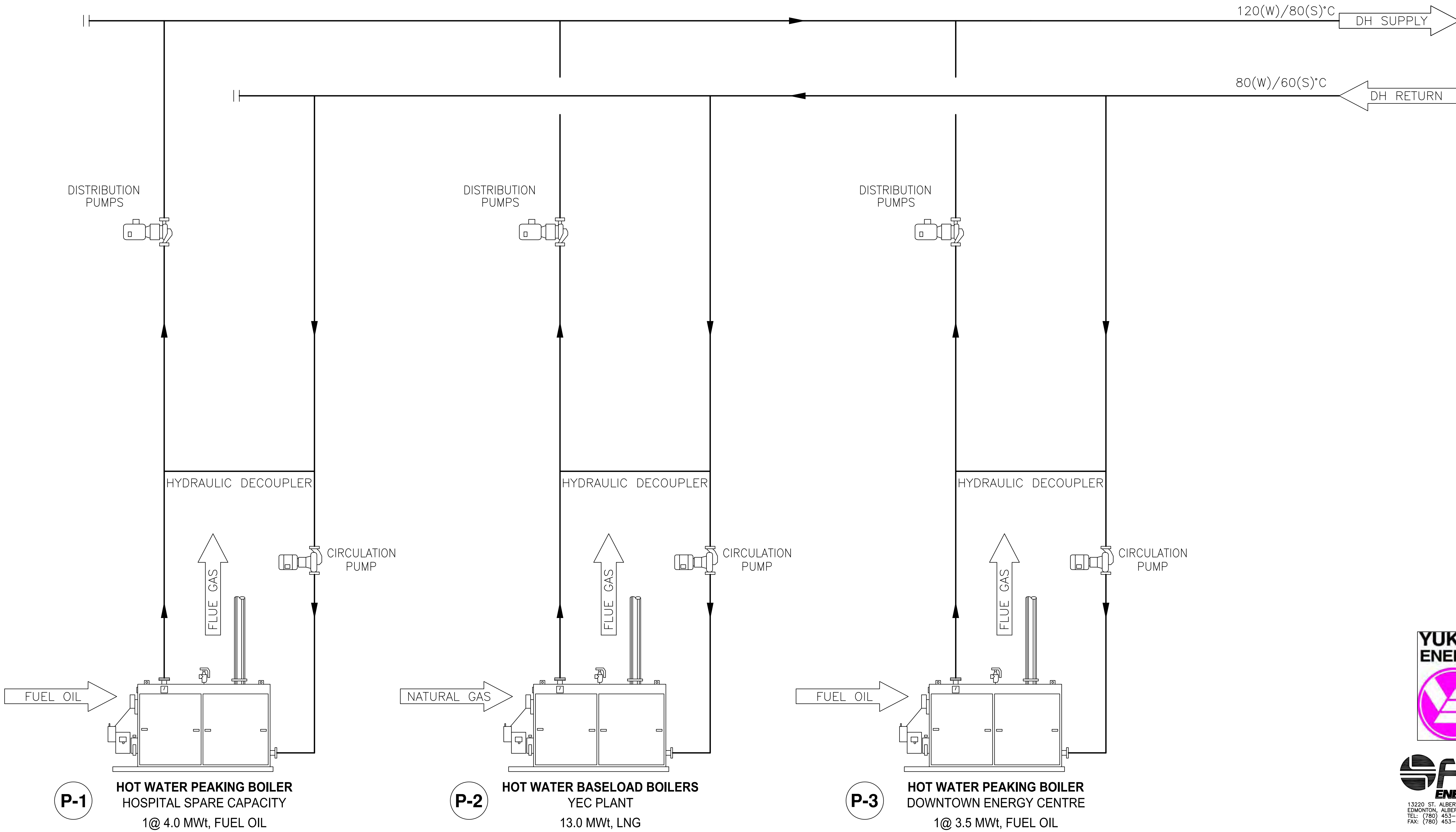

Alt #2 & 3 - Biomass Boiler
Heating Load Duration Curve
Peak Demand 13.9 MW
Baseload (43.2% of Peak) 6 MW
Baseload Energy (86.1% of Energy) 33080 MWh
NG Peaking Energy (13.8% of Energy) 5290 MWh
Fuel Oil (< 1 % of Energy) 30 MWh
Total Energy (100 %) 38400 MWh
Peaking Boilers
Biomass
Planned Outage
Two Weeks
(Peaking Boilers)
Peak Heating Load (MW)
No. of hours
0
1000
2000
3000
4000
5000
6000
7000
8000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15


Alt #4 & 5 - Biomass Boiler with ORC
Heating Load Duration Curve
Peak Demand 13.9 MW
Baseload (43.2% of Peak) 6 MW
Baseload Energy (86.1% of Energy) 33080 MWh
NG Peaking Energy (13.8% of Energy) 5290 MWh
Fuel Oil (< 1 % of Energy) 30 MWh
Total Energy (100 %) 38400 MWh
Electrical Production - 6840 MWh(e)
Peaking Boilers
Biomass
Planned Outage
Two Weeks
(Peaking Boilers)
Peak Heating Load (MW)
No. of hours
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
0
1000
2000
3000
4000
5000
6000
7000
8000


Alt #6, 7 & 8 - Reciprocating Cogeneration Unit
Heating Load Duration Curve
Peak Demand 13.9 MW
Baseload (43.2% of Peak) 6 MW
Baseload Energy (67% of Energy) 25700 MWh
NG Peaking Energy (33% of Energy) 12670 MWh
Fuel Oil (< 1 % of Energy) 30 MWh
Total Energy (100 %) 38400 MWh
Electrical Production - 29360 MWh(e)
Peaking Boilers
Cogen Heat Recovery
Peaking Boilers
Peak Heating Load (MW)
No. of hours
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
0
1000
2000
3000
4000
5000
6000
7000
8000

C.4 Alternative Energy Scenario Sketches

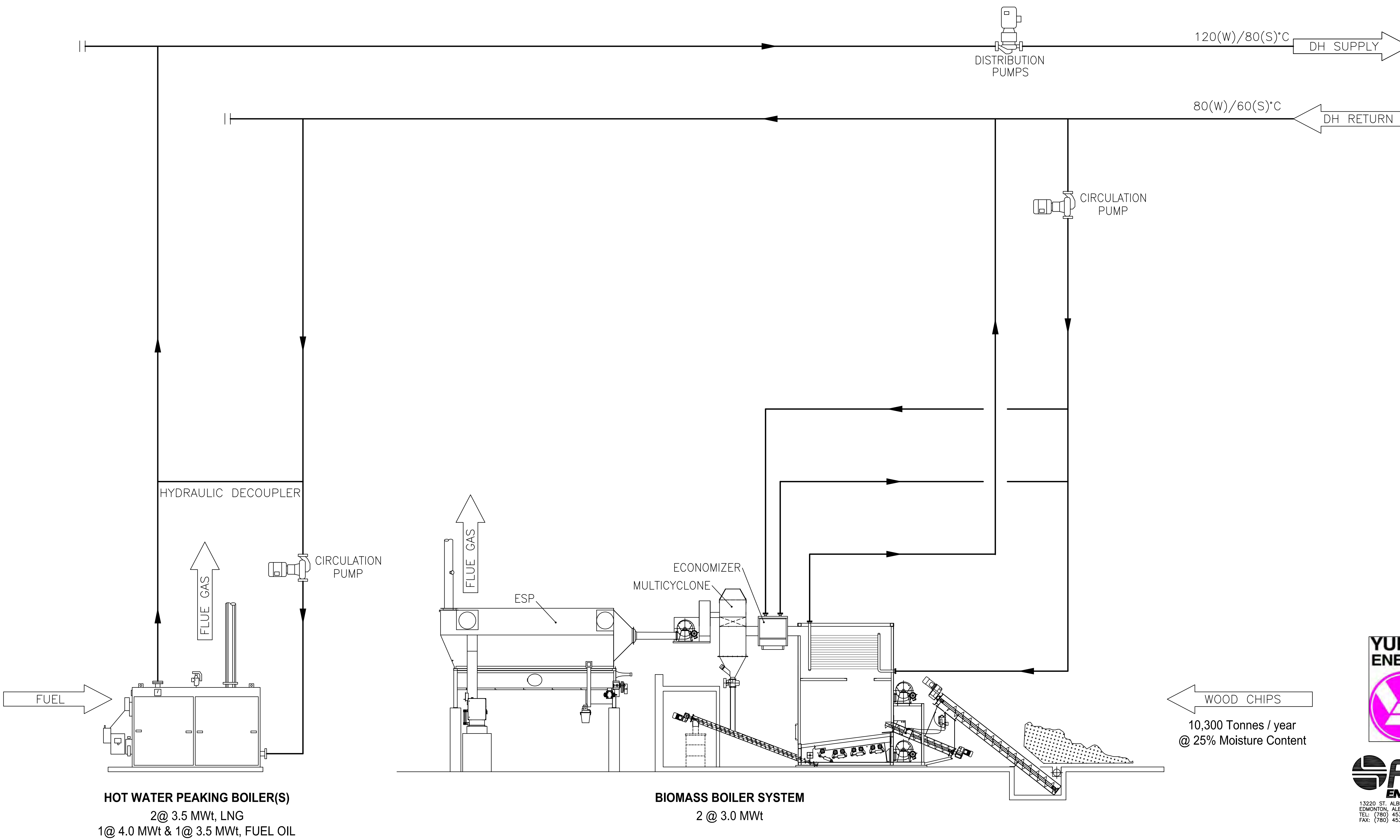
ALT #1 - LIQUEFIED NATURAL GAS BOILER SYSTEM



YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

ALT #2 - BIOMASS BOILER SYSTEM - WOOD CHIPS



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EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
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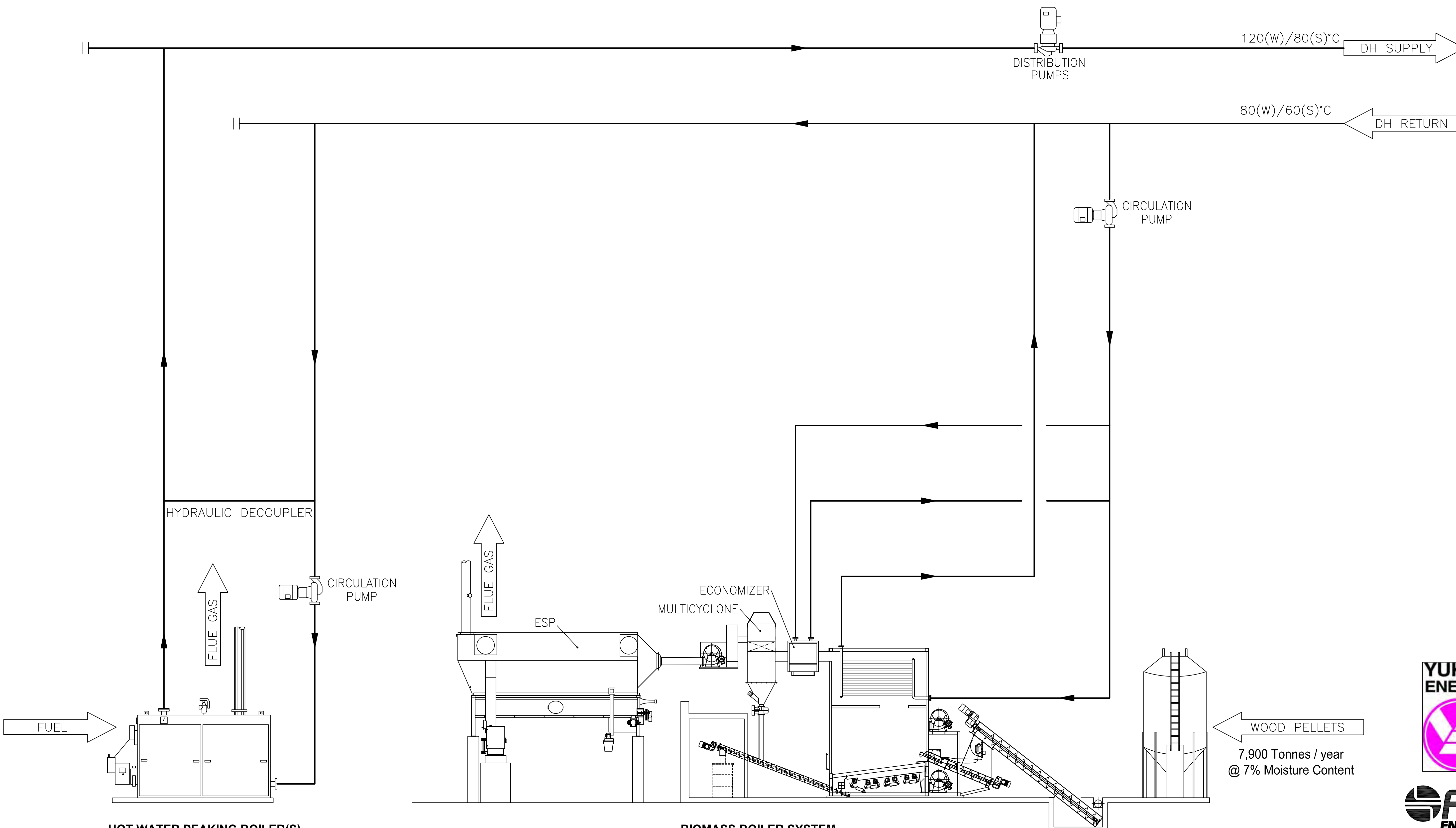
ALT #3 - BIOMASS BOILER SYSTEM - WOOD PELLETS



HOT WATER PEAKING BOILER(S)
2@ 3.5 MWt, LNG
1@ 4.0 MWt & 1@ 3.5 MWt, FUEL OIL

BIOMASS BOILER SYSTEM
2 @ 3.0 MWt

YUKON ENERGY

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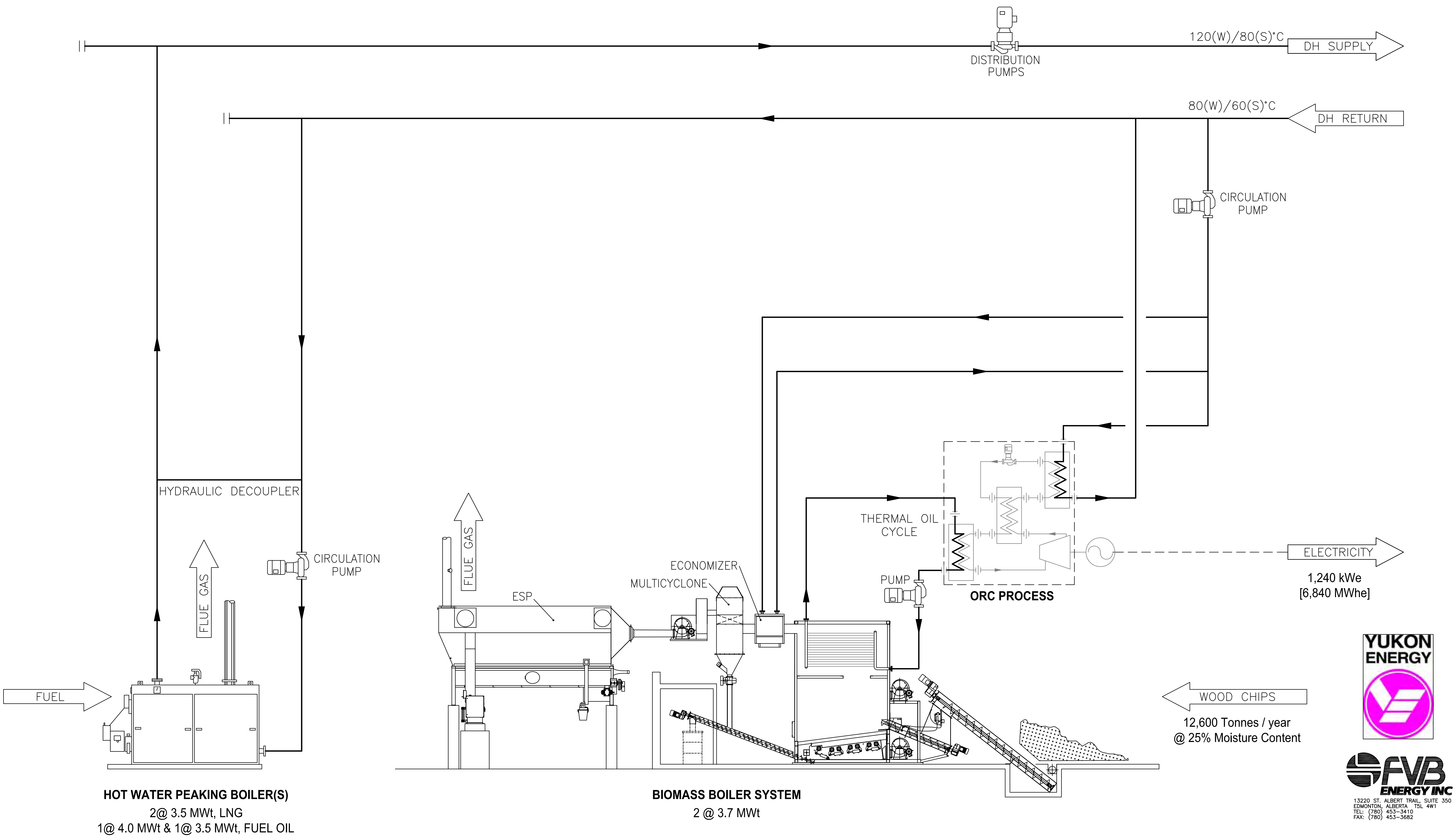
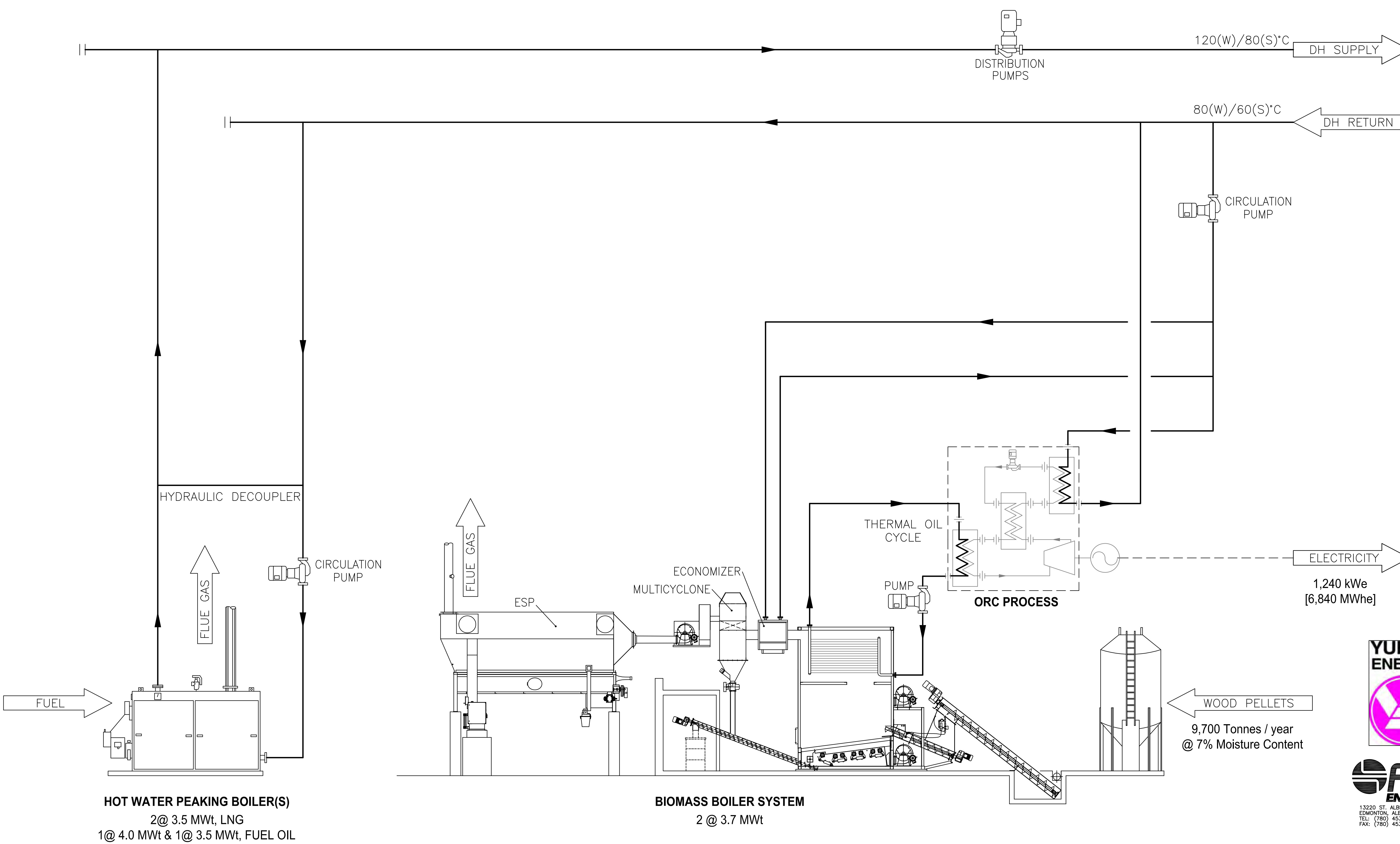
FAX: (780) 453-3682

ALT #4 - BIOMASS BOILER SYSTEM COMBINED WITH ORC CYCLE - WOOD CHIPS



ALT #5 - BIOMASS BOILER SYSTEM COMBINED WITH ORC CYCLE - WOOD PELLETS

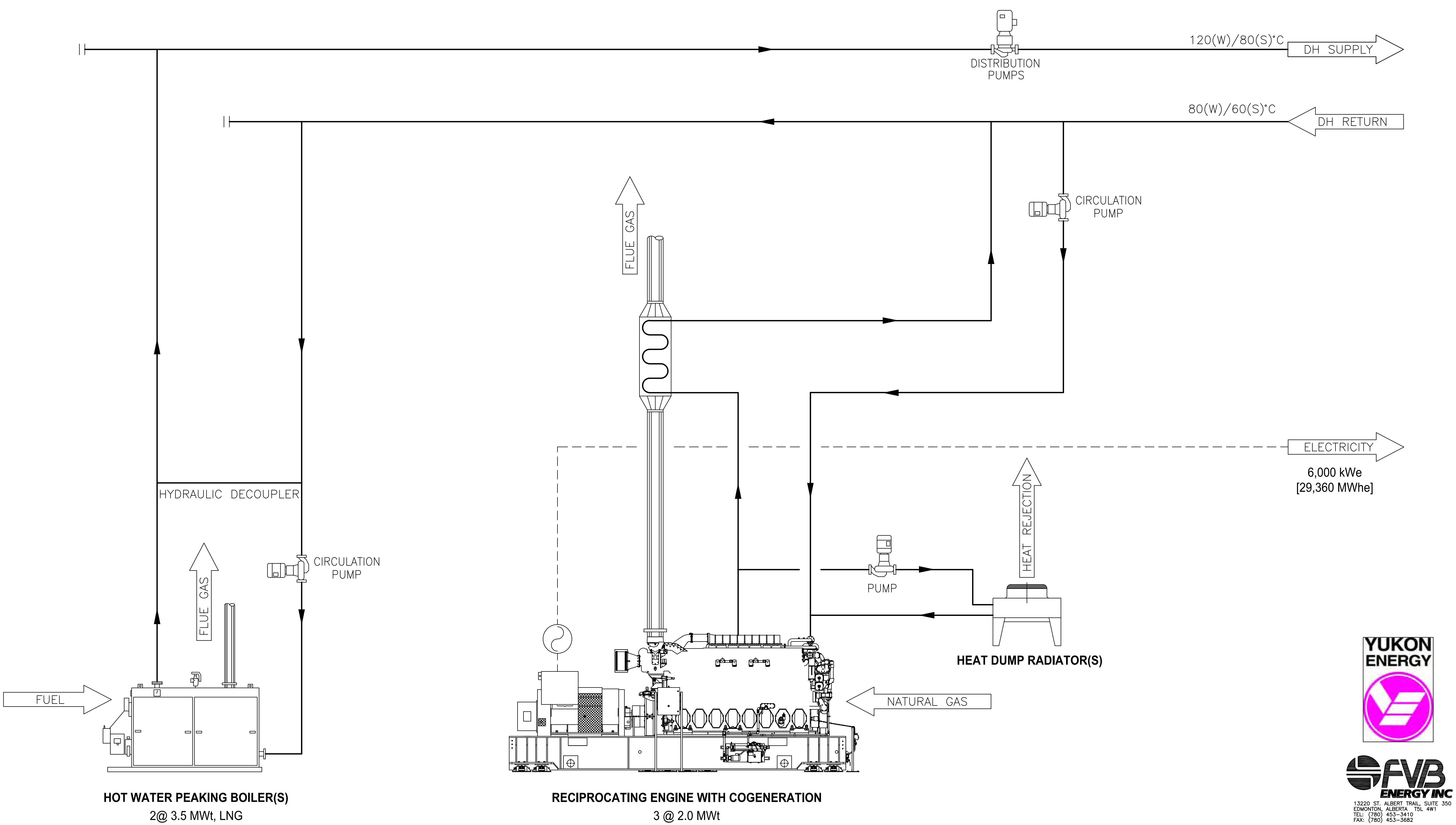


YUKON ENERGY

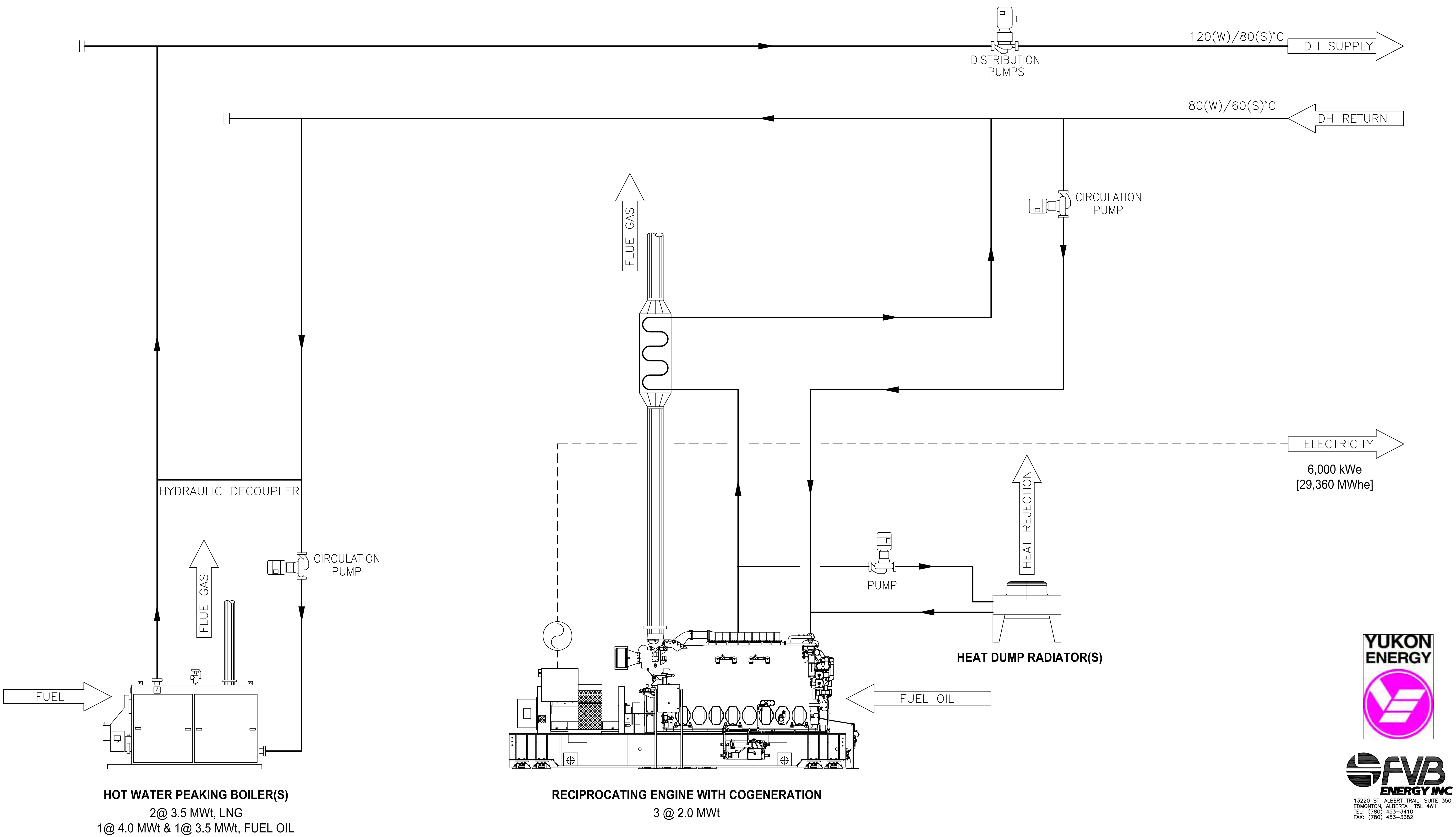
FVB ENERGY INC

13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

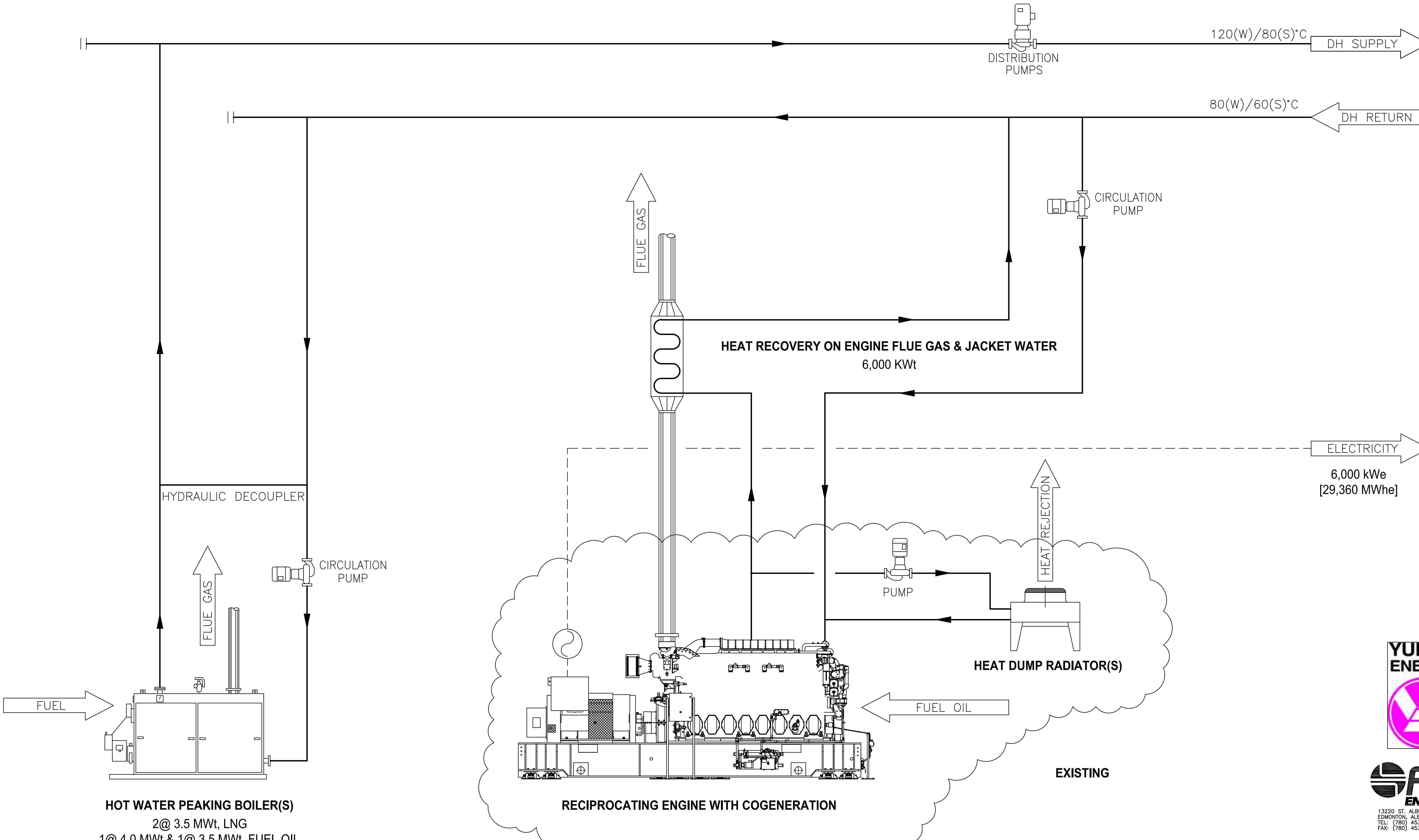
ALT #6 - RECIPROCATING ENGINE COGENERATION SYSTEM - NATURAL GAS



ALT #7 - RECIPROCATING ENGINE COGENERATION SYSTEM - FUEL OIL



ALT #8 - HEAT RECOVERY SYSTEM ON EXISTING RECIPROCATING ENGINE - FUEL OIL



YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

C.5 Screening Summary Sheets

PROJECT NAME:	Whitehorse District Energy System Feasibility Study Resource Screening Options - DRAFT Electrical Sales Price @ $150 / MWh(e)
CLIENT:	Yukon Energy
PROJECT No.	211313
PREPARED BY:	G. Saskiw
REVIEWED BY:	R. Doyle
DATA SOURCE:	FVB Database
REVISION No.	4
REVISION DATE:	May 3, 2012
SHEET:	1 of 2

PRELIMINARY SCREENING ANALYSIS	**Alt #1** **Central Plant LNG Boiler** **Full Buildout**	**Alt #2** **Biomass Boiler - Wood Chips** **Full Buildout**	**Alt #3** **Biomass Boiler - Wood Pellets** **Full Buildout**	**Alt #4** **Biomass Boiler with ORC Cycle - Wood Chips** **Full Buildout**	**Alt #5** **Biomass Boiler with ORC Cycle - Wood Pellets** **Full Buildout**	**Alt #6** **Reciprocating Engine Cogeneration - LNG** **Full Buildout**	**Alt #7** **Reciprocating Engine Cogeneration - Fuel Oil** **Full Buildout**	**Alt #8** **Heat Recovery on Existing Reciprocating Engine** **Full Buildout**
Loads								
Contract Load	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW
Diversified Load	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW
Peaking Thermal Energy	*38,400 MWh*	*5,300 MWh*	*5,300 MWh*	*5,300 MWh*	*5,300 MWh*	*12,700 MWh*	*12,700 MWh*	*12,700 MWh*
Alt Thermal Energy	*0 MWh*	*33,100 MWh*	*33,100 MWh*	*33,100 MWh*	*33,100 MWh*	*25,700 MWh*	*25,700 MWh*	*25,700 MWh*
Total Displaced Thermal Energy	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh
Peaking / Back-up Heating Plant(s)								
Annual Fuel Cost	*$2,633,100*	*$366,600*	*$366,600*	*$366,600*	*$366,600*	*$872,100*	*$872,100*	*$872,100*
Annual Electricity Cost	*$80,900*	*$11,200*	*$11,200*	*$11,200*	*$11,200*	*$26,800*	*$26,800*	*$26,800*
Annual Operations and Maintenance Cost	*$103,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*
Annual Staffing Cost	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*
Net Annualized Peaking/BU Capital (6.2%, 25 yrs)	*$817,100*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*
Total Annual Cost of Peaking/Back-up Heating Plant Energy Production	$3,790,100	$1,184,800	$1,184,800	$1,184,800	$1,184,800	$1,705,900	$1,705,900	$1,705,900
Cost of Peaking Plant/Back-up Thermal Energy	*$99 /MWh*	*$223 /MWh*	*$223 /MWh*	*$223 /MWh*	*$223 /MWh*	*$134 /MWh*	*$134 /MWh*	*$134 /MWh*
Alternate Heating Baseload Plant								
Annual Fuel Cost	*$0*	*$1,549,100*	*$2,584,900*	*$1,895,000*	*$3,173,800*	*$4,642,500*	*$7,213,900*	*$7,933,500*
Annual Electricity Cost	*$0*	*$149,800*	*$149,800*	*$149,800*	*$149,800*	*$142,800*	*$129,500*	*$142,400*
Annual Electricity Production Sales @ $150 / MWh(e)	*$0*	*$0*	*$0*	*-$1,026,000*	*-$1,026,000*	*-$4,404,000*	*-$4,404,000*	*-$4,404,000*
Annual Operations and Maintenance Cost	*$0*	*$210,000*	*$189,000*	*$283,000*	*$260,000*	*$465,300*	*$465,300*	*$465,300*
Annual Staffing Cost	*$0*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*
Net Annualized Peaking/BU Capital (6.2%, 25 yrs)	*$0*	*$837,100*	*$837,100*	*$1,221,300*	*$1,221,300*	*$1,195,800*	*$1,076,200*	*$191,300*
Total Annual Cost of Alternate Heating Baseload Plant Energy Production	N/A	$2,824,000	$3,838,800	$2,601,100	$3,856,900	$2,120,400	$4,558,900	$4,406,500
Cost of Alternate Baseload Thermal Energy	*N/A*	*$85 /MWh*	*$116 /MWh*	*$79 /MWh*	*$117 /MWh*	*$83 /MWh*	*$177 /MWh*	*$171 /MWh*
Total Annual Cost of Thermal Energy Production	**$3,790,100**	**$4,008,800**	**$5,023,600**	**$3,785,900**	**$5,041,700**	**$3,826,300**	**$6,264,800**	**$6,112,400**
Total Blended $/MWh Heating	***$99 /MWh***	***$104 /MWh***	***$131 /MWh***	***$99 /MWh***	***$131 /MWh***	***$100 /MWh***	***$163 /MWh***	***$159 /MWh***
Total Green House Gas Outputs (prelim. estimate)	8,800 tonnes	1,700 tonnes	1,700 tonnes	1,500 tonnes	1,500 tonnes	18,400 tonnes	22,400 tonnes	24,300 tonnes
Green House Gas Savings over Business As Usual Case	**5,950 tonnes**	**13,100 tonnes**	**13,100 tonnes**	**18,240 tonnes**	**18,240 tonnes**	**17,720 tonnes**	**13,770 tonnes**	**11,830 tonnes**

PROJECT NAME:	Whitehorse District Energy System Feasibility Study Resource Screening Options - DRAFT Electrical Sales Price @ $200 / MWh(e)
CLIENT:	Yukon Energy
PROJECT No.	211313
PREPARED BY:	G. Saskiw
REVIEWED BY:	R. Doyle
DATA SOURCE:	FVB Database
REVISION No.	4
REVISION DATE:	May 3, 2012
SHEET:	2 of 2

PRELIMINARY SCREENING ANALYSIS	**Alt #1** **Central Plant LNG Boiler** **Full Buildout**	**Alt #2** **Biomass Boiler - Wood Chips** **Full Buildout**	**Alt #3** **Biomass Boiler - Wood Pellets** **Full Buildout**	**Alt #4** **Biomass Boiler with ORC Cycle - Wood Chips** **Full Buildout**	**Alt #5** **Biomass Boiler with ORC Cycle - Wood Pellets** **Full Buildout**	**Alt #6** **Reciprocating Engine Cogeneration - LNG** **Full Buildout**	**Alt #7** **Reciprocating Engine Cogeneration - Fuel Oil** **Full Buildout**	**Alt #8** **Heat Recovery on Existing Reciprocating Engine** **Full Buildout**
Loads								
Contract Load	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW	16.3 MW
Diversified Load	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW	13.9 MW
Peaking Thermal Energy	*38,400 MWh*	*5,300 MWh*	*5,300 MWh*	*5,300 MWh*	*5,300 MWh*	*12,700 MWh*	*12,700 MWh*	*12,700 MWh*
Alt Thermal Energy	*0 MWh*	*33,100 MWh*	*33,100 MWh*	*33,100 MWh*	*33,100 MWh*	*25,700 MWh*	*25,700 MWh*	*25,700 MWh*
Total Displaced Thermal Energy	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh	38,400 MWh
Peaking / Back-up Heating Plant(s)								
Annual Fuel Cost	*$2,633,100*	*$366,600*	*$366,600*	*$366,600*	*$366,600*	*$872,100*	*$872,100*	*$872,100*
Annual Electricity Cost	*$80,900*	*$11,200*	*$11,200*	*$11,200*	*$11,200*	*$26,800*	*$26,800*	*$26,800*
Annual Operations and Maintenance Cost	*$103,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*	*$73,000*
Annual Staffing Cost	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*	*$156,000*
Net Annualized Peaking/BU Capital (6.2%, 25 yrs)	*$817,100*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*	*$578,000*
Total Annual Cost of Peaking/Back-up Heating Plant Energy Production	$3,790,100	$1,184,800	$1,184,800	$1,184,800	$1,184,800	$1,705,900	$1,705,900	$1,705,900
Cost of Peaking Plant/Back-up Thermal Energy	*$99 /MWh*	*$223 /MWh*	*$223 /MWh*	*$223 /MWh*	*$223 /MWh*	*$134 /MWh*	*$134 /MWh*	*$134 /MWh*
Alternate Heating Baseload Plant								
Annual Fuel Cost	*$0*	*$1,549,100*	*$2,584,900*	*$1,895,000*	*$3,173,800*	*$4,642,500*	*$7,213,900*	*$7,933,500*
Annual Electricity Cost	*$0*	*$149,800*	*$149,800*	*$149,800*	*$149,800*	*$142,800*	*$129,500*	*$142,400*
Annual Electricity Production Sales @ $200 / MWh(e)	*$0*	*$0*	*$0*	*-$1,368,000*	*-$1,368,000*	*-$5,872,000*	*-$5,872,000*	*-$5,872,000*
Annual Operations and Maintenance Cost	*$0*	*$210,000*	*$189,000*	*$283,000*	*$260,000*	*$465,300*	*$465,300*	*$465,300*
Annual Staffing Cost	*$0*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*	*$78,000*
Net Annualized Peaking/BU Capital (6.2%, 25 yrs)	*$0*	*$837,100*	*$837,100*	*$1,221,300*	*$1,221,300*	*$1,195,800*	*$1,076,200*	*$191,300*
Total Annual Cost of Alternate Heating Baseload Plant Energy Production	N/A	$2,824,000	$3,838,800	$2,259,100	$3,514,900	$652,400	$3,090,900	$2,938,500
Cost of Alternate Baseload Thermal Energy	*N/A*	*$85 /MWh*	*$116 /MWh*	*$68 /MWh*	*$106 /MWh*	*$25 /MWh*	*$120 /MWh*	*$114 /MWh*
Total Annual Cost of Thermal Energy Production	**$3,790,100**	**$4,008,800**	**$5,023,600**	**$3,443,900**	**$4,699,700**	**$2,358,300**	**$4,796,800**	**$4,644,400**
Total Blended $/MWh Heating	***$99 /MWh***	***$104 /MWh***	***$131 /MWh***	***$90 /MWh***	***$122 /MWh***	***$61 /MWh***	***$125 /MWh***	***$121 /MWh***
Total Green House Gas Outputs (prelim. estimate)	8,800 tonnes	1,700 tonnes	1,700 tonnes	1,500 tonnes	1,500 tonnes	18,400 tonnes	22,400 tonnes	24,300 tonnes
Green House Gas Savings over Business As Usual Case	**5,950 tonnes**	**13,100 tonnes**	**13,100 tonnes**	**18,240 tonnes**	**18,240 tonnes**	**17,720 tonnes**	**13,770 tonnes**	**11,830 tonnes**

Appendix D- Capital Cost Summary

D.1 Energy Centre Capital Cost Assumptions

Energy Centre Capital Cost Assumptions

This concept design estimate is intended to provide a realistic assessment of the direct and indirect construction costs for the proposed construction of the energy centre to service the proposed Whitehorse community energy system. The estimated construction costs contained in this report are based on preliminary concept schematic design drawings prepared by FVB.

The construction estimates provide a reasonable cost envelope within which the project design can be developed. The costing information and data contained herein represent FVB's best professional judgment in light of the knowledge and information available to FVB Energy Inc. at the time of preparation.

Further estimates should be provided based on more detailed design information.

Inclusions & General Assumptions

The following are specifically included in the cost estimate:

- All costs are 2012, 2nd Quarter, Canadian Dollars
- Engineering is allowed for
- Contingency is allowed for
- Contractor soft costs are allowed for
- Assumes a competitive construction tender process

Exclusions

The following are specifically excluded from the cost estimate:

- All taxes
- Special soil conditions i.e. blasting or large in fill requirements
- Utility interconnect charges
- Costs for Environmental investigation/remediation
- Fees for Environmental permits and regulatory fees not included
- Fees for permits, right-of-ways, and easements not included
- Cost of land acquisition, easements and right of ways are not included
- Legal Fees and expenses
- Loose Furnishings and equipment
- Accelerated schedule
- Construction price escalation
- Owners project development costs

Accuracy of Costing Assumptions

The cost estimates provided are Class 4 (as per AACE International No.17R-97) and thus are preliminary with a level of accuracy of +25% and –10%.

Energy Centre #1

The energy centre budget has been based on the following:

- Concept drawings:
  - Plant P-1 Steam Converter Station Schematic, SK-1313-001
  - Plant P-1 Steam Converter Station Preliminary Equipment Layout, SK-1313-101
  - Plant P-1 Electrical Single Line Diagram, E-1313-001

Sized to deliver a Heating Capacity of 4 MW_{th} thermal. The heating capacity is assumed to be provided by the following:

- One (1) 4.0 MW_{th} heat exchanger
- One condensate receiver tank
- Two (2) condensate return pumps
- Two (2) centrifugal distribution pumps each sized at 100% of peak load
- Steam and condensate piping to interconnect to existing hospital system

Building

The energy centre building budget assumes a purpose built (fit for function) building consisting of the following:

- A stand-alone building near the hospital mechanical room housing the pumps, heating system auxiliaries, and electrical panels, 32 m^2, with an assumed building height of 4 m at a cost of $250 per square foot.
- Generally all process areas assumed to be 8 inch thick reinforced slab on grade.
- Assumes required utility services at lot line.
- Assumes no allocation for electric utility primary service. Tie-in to occur with existing hospital electrical infrastructure.
- Assumes no blasting or significant bedrock removal required for foundations.

Emergency Power

The energy centre #1 emergency power is assumed to be fed from existing hospital infrastructure.

Steam Conversion System

Generally the steam converting station has been based on the following;

- FVB historical equipment cost database

Construction Soft Costs

Construction soft costs include for the following:

- 10% for GC OH&P
- 2.5% for permitting, bonding, & insurance
- 2.5 % for construction management & supervision

Owner's Soft Costs

Owner's soft costs include for the following:

- 20% for owners engineering costs
- 10% for contingency

Energy Centre #2 – Biomass Design Basis

The energy centre budget has been based on the following

- Concept drawings
  - o Energy Centre P-2 Heating Energy centre Schematic, SK-1313-002
  - o Energy Centre P-2 Biomass Heat Recovery Schematic, SK-1313-003
  - o Energy Centre P-2 Heating Energy centre Preliminary Equipment Layout, SK-1313-102
  - o Energy Centre P-2 Electrical Single Line Diagram ORC Generation Option, E-1313-002A

The budget includes a capital allowance associated with the primary electric substation, and the buried electrical duct banks to carry the primary service from property line into the building.

Sized to deliver a Heating Capacity of 14 MW_{th} thermal. The heating capacity is assumed to be provided by the following:

- o Two (2) 4.0 MW_{th} fuel oil hot water peaking boilers
- o Single 12 m tall stack serving all the fuel oil boilers
- o Two (2) 3.5 MW_{th} biomass combustors complete with fuel feed auxiliaries
- o One (1) 6.0 MW_{th} hot oil heat exchanger
- o Separate 12 m tall stack serving the biomass unit with:
  - ▪ Multi-cyclone unit
  - ▪ Exhaust economizer
  - ▪ Electrostatic Precipitator (ESP)
- o One (1) 1.21 MW_e Organic Rankine cycle turbine complete with heat recovery and electrical generation auxiliaries
- o Two (2) circulation pumps for the biomass exhaust economizer
- o One (1) circulation pump for the ORC condenser
- o One (1) circulation pump for the hot oil heat exchange
- o Two (2) circulation pumps for the fuel oil boilers

- o Three (3) centrifugal distribution pumps each sized at 50% of peak load

Building

The energy centre building budget assumes a purpose built (fit for function) building consisting of the following:

- Building costs and auxiliaries are built into the budget price received from vendors for the biomass and ORC units, including a separate room for the ORC unit.
- A building housing the fuel oil peaking boilers, pumps, heating system auxiliaries, electrical room, and staff areas, 336 m^2, with an assumed building height of 6 m at a cost of $250 per square foot
- The building footprint is sized conservatively for the equipment allowed and this can be refined at the design stage
- Generally all process areas assumed to be 8 inch thick reinforced slab on grade.
- Assumes an external fuel oil storage tanks (~140,000 L) sized for 7 days storage (at full output)
- Assumes allocation for automatic ash collecting system
- Assumes required utility services at lot line
- Exterior primary transformers, ESP, and heat dump radiators on concrete pads
- Assumes no allocation for electric utility primary service
- Assumes no blasting or significant bedrock removal required for foundations

Emergency Power

The energy centre emergency power budget has been based on the following;

- The oil fired emergency generator will be sized to properly shut down the biomass system (250 kW_e) during a power outage as well as provide the ability to service a minimum of 70% of the peak thermal capacity after the biomass unit has been shut down. This assumption will have to be reviewed once final motor loads are determined for the energy centre.
- Twenty four (24) hours of above ground oil storage for the emergency genset.

Biomass Hot Water Energy System

Generally the biomass energy system has been based on the following;

Proposal from Wellons Canada dated July 7, 2012 for the supply and mechanical installation of a package for a 7 MW_{th} biomass fired hot water energy system. The scope of supply includes fuel bin unloading system, combustion system, hot water heating system, Turboden TD 14 ORC system and Electrostatic Precipitator.

The biomass fuel type used as the basis for the concept is considered to have a humidity of 25%, and higher heat value of 20.6 GJ/tonne (8,856 BTU/lb).

The proposed concept envisions the use of "shuffle floor" trailers for delivery to a hidden fuel bin located within the energy centre. Conveyors will automatically move the fuel to the fuel storage area. Fuel rakes automatically deliver fuel to the boilers as required by the heating load.

Assumes multi-cyclone and electrostatic precipitator to meet the air emission limits for filterable particulate matter.

Construction Soft Costs

Construction soft costs of the fuel oil boilers include for the following:

- 10% for GC OH&P
- 2.5% for permitting, bonding, & insurance
- 4 % for construction management & supervision

Construction soft costs of the biomass and ORC systems include for the following:

- 2.5% for GC OH&P
- 2.5% for permitting, bonding, & insurance
- 1 % for construction management & supervision

Owner's Soft Costs

Owner's soft costs of the fuel oil boilers include for the following:

- 14% for owners engineering costs
- 10% for contingency

Owner's soft costs of the biomass and ORC systems include for the following:

- 2.5% for owners engineering costs
- 6.2% for contingency

Energy Centre #2 – LNG Design Basis

The energy centre budget has been based on the following:

- Concept drawings
    - o Energy Centre P-2 Heating Energy centre Schematic, SK-1313-005
    - o Energy Centre P-2 Heating Energy centre Schematic, SK-1313-006
    - o Energy Centre P-2 Heating Energy centre c/w Cogen Preliminary Equipment Layout, SK-1313-104
    - o Energy Centre P-2 Electrical Single Line Diagram Reciprocating Generation Option, E-1313-002

The budgets include a capital allowance associated with the primary electric substation, and the buried electrical duct banks to carry the primary service from property line into the building.

The budgets assume LNG is delivered to the energy centre building. No additional costs for LNG storage, nor piping systems have been included in the budget.

Sized to deliver a Heating Capacity of 14.1 MW_{th} thermal. The heating capacity is assumed to be provided by the following:

- Two (2) 4.0 MW_{th} LNG / Fuel oil hot water peaking boilers
- LNG vapourized and pre-heated using exchanger with hot water exchange
- Single 12 m tall stack serving all the peaking boilers
- Two (2) 3.3 MW_e LNG fueled cogeneration engines with heat recovery from:
  - Mixture Intercooler – 1st Stage heat exchange
  - Lube oil heat exchange
  - Engine jacket water heat exchange
  - Heat exchange from exhaust gas with bypass control
- Glycol heat dump loop with externally located radiator type heat dumps and freeze protection pumps
- LNG vapourized and pre-heated using exchanger with heat exchange from the 2nd Stage Intercooler
- Exhaust gas silencer(s)
- Two (2) circulation pumps for the fuel oil boilers
- Three (3) centrifugal distribution pumps each sized at 50% of peak load
- Two (2) CHP engine exhaust stacks

Building

The energy centre building budget assumes a purpose built (fit for function) building consisting of the following:

- A building housing the LNG peaking boilers, pumps, heating system auxiliaries, and electrical room, 336 m^2, with an assumed building height of 6 m at a cost of $250 per square foot.
- A building housing the LNG cogeneration units, 466 m^2, with an assumed building height of 9 m at a cost of $250 per square foot
- The building footprint is sized conservatively for the equipment allowed and this can be refined at the design stage
- Assumes an external fuel oil storage tanks (~22,000 L) sized for 2 days storage (at full output) as back-up to LNG fuel system (for the boilers only).
- Generally all process areas assumed to be 8 inch thick reinforced slab on grade
- Assumes required utility services at lot line
- Exterior primary transformers and heat dump radiators on concrete pads
- Assumes no allocation for electric utility primary service
- Assumes anti-islanding protection
- Assumes no blasting or significant bedrock removal required for foundations

Emergency Power

The energy centre emergency power budget has been based on the following:

- One oil fired emergency power engine at 200 kW_e. This assumption will have to be reviewed once final motor loads are determined for the energy centre
- The emergency generator will be sized to provide emergency service to the peaking boilers for during a power outage
- The cogeneration engines are designed to be islanding, providing electricity during power outage
- Twenty four (24) hours of above ground oil storage for the emergency genset

LNG Cogeneration Energy System

Generally the LNG cogeneration energy system has been based on the following:

Proposal from GE Jenbacher dated July 10, 2012 for the supply and mechanical installation of a 6.6 MW_e LNG fuelled cogeneration system. The scope of supply includes radiators, heat exchangers, and exhaust systems.

Construction Soft Costs

Construction soft costs include for the following:

- 10% for GC OH&P
- 2.5% for permitting, bonding, & insurance
- 4 % for construction management & supervision

Owner's Soft Costs

Owner's soft costs include for the following:

- 14% for owners engineering costs
- 10% for contingency

Energy Centre #3

The energy centre budget has been based on the following:

- Concept drawings;
  - Energy Centre P-3 Heating Energy Centre Schematic, SK-1313-004
  - Energy Centre P-3 Downtown Energy Centre Preliminary Equipment Layout, SK-1313-103
  - Energy Centre P-3 Electrical Single Line Diagram, E-1313-003

Sized to deliver a Heating Capacity of 4 MW_{th} thermal. The heating capacity is assumed to be provided by the following:

  - One (1) 4.0 MW_{th} fuel oil back-up boiler
  - One (1) boiler circulation pump

- Two (2) centrifugal distribution pumps each sized at 100% of peak load
- Single 12 m tall stack serving the back-up boiler(s)

Building

The energy centre building budget has been based on the following:

- Assumes a purpose built (fit for function) building housing the boilers, pumps, heating system auxiliaries, electrical room, and staff areas; 140 m^2, with assumed building height of 5 m at a cost of $200 per square foot
- The building footprint is sized conservatively for the equipment allowed and this can be refined at the design stage.
- Generally all process areas assumed to be 8 inch thick reinforced slab on grade.
- Assumes an external fuel oil storage tanks (~70,000 L) sized for 7 days storage (at full output)
- Assumes no allocation for electric utility primary service and energy centre substation
- Assumes no blasting or significant bedrock removal required for foundations.

Emergency Power

The energy centre emergency power budget has been based on the following:

One oil fired emergency power engine at 30 kWe. This assumption will have to be reviewed once final motor loads are determined for the energy centre.

Twenty four (24) hours of above ground oil storage for the emergency genset.

Fuel Oil Boiler Hot Water Energy System

Generally the fuel oil boiler has been based on the following:

- FVB historical equipment cost database
- Sterling Boiler budget price from similar study

Construction Soft Costs

Construction soft costs include for the following:

- 10% for GC OH&P
- 2.5% for permitting, bonding, & insurance
- 4 % for construction management & supervision

Owner's Soft Costs

Owner's soft costs include for the following:

- 20% for owners engineering costs
- 10% for contingency

D.2 Biomass Concept - Energy Centre Capital Cost Summary

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	29-Jun-12
Revision #:	1
Prepared by:	J Chin, P.Eng.
Reviewed by:	R.Doyle, P.Eng.
Description:	Plant 1 - 4 MW Steam Converter Station at Hospital

Whitehorse Plant 1	**Steam Conversion**	
	Installed Capacity	**Totals** ($)
Hot Water		
Architectural/Civil/Structural/Utilites	32 m2	$110,000
Electrical Installation	200 kVA	$101,000
Mechanical Installation	4. MWt	$426,000
Major Equipment		$160,000
Major Equipment (Alt Capacity)		$0
GC Admin, OH&P (No Taxes)		$104,000
Subtotal Construction		**$901,000**
Soft Costs		
Engineering		$180,000
Contingency		$90,000
Total		**$1,171,000**

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	29-Jun-12
Revision #:	1
Prepared by:	J Chin, P.Eng.
Reviewed by:	R.Doyle, P.Eng.
Description:	Two X 4.0 MWth Fuel Oil Boilers, Two X 3.5 MWth Biomass Combustors & 1.24 MWe ORC

Whitehorse Plant 2	**Full Plant**		**Boiler Plant**		**Biomass & ORC**	
	Installed Capacity	**Totals** ($)	**Installed Capacity**	**Totals** ($)	**Installed Capacity**	**Totals** ($)
Hot Water						
Architectural/Civil/Structural/Utilites	1,300 m2	$1,143,000	300 m2	$1,143,000	1,000 m2	$0
Electrical Installation	2,000 kVA	$761,000	500 kVA	$456,000	1,500 kVA	$305,000
Mechanical Installation	14. MWt	$1,785,000	8. MWt	$1,343,000	6. MWt	$442,000
Major Equipment (Oil Blr +Biomass)		$12,581,000		$955,000	7.5 MWt	$11,626,000
Major Equipment (ORC)		$4,200,000		$0	1,200 kWe	$4,200,000
GC Admin, OH&P (No Taxes)		$1,146,000		$547,000		$599,000
Subtotal Construction		**$21,616,000**		**$4,444,000**		**$17,172,000**
Soft Costs						
Engineering		$1,180,000		$665,000		$515,000
Contingency		$1,505,000		$444,000		$1,061,000
Total		**$24,301,000**		**$5,553,000**		**$18,748,000**

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	29-Jun-12
Revision #:	1
Prepared by:	J Chin, P.Eng.
Reviewed by:	R.Doyle, P.Eng.
Description:	Plant 3 - 4 MW HW Boiler Plant - Oil Fired Only

Whitehorse Plant 3	**Boiler Plant**	
	Installed Capacity	**Totals** ($)
Hot Water		
Architectural/Civil/Structural/Utilites	140 m2	$367,000
Electrical Installation	250 kVA	$228,000
Mechanical Installation	4. MWt	$478,000
Major Equipment (Oil Blr)		$473,000
GC Admin, OH&P (No Taxes)		$208,000
Subtotal Construction		**$1,754,000**
Soft Costs		
Engineering		$377,000
Contingency		$175,000
Total		**$2,306,000**

D.3 LNG Concept - Energy Centre Capital Cost Summary

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	29-Jun-12
Revision #:	1
Prepared by:	J Chin, P.Eng.
Reviewed by:	R.Doyle, P.Eng.
Description:	Plant 1 - 4 MW Steam Converter Station at Hospital

Whitehorse Plant 1	**Steam Conversion**	
	Installed Capacity	**Totals** ($)
Hot Water		
Architectural/Civil/Structural/Utilites	32 m2	$110,000
Electrical Installation	200 kVA	$101,000
Mechanical Installation	4. MWt	$426,000
Major Equipment		$160,000
Major Equipment (Alt Capacity)		$0
GC Admin, OH&P (No Taxes)		$104,000
Subtotal Construction		**$901,000**
Soft Costs		
Engineering		$180,000
Contingency		$90,000
Total		**$1,171,000**

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	23-Jul-12
Revision #:	0
Prepared by:	G. Saskiw
Reviewed by:	John Chin, P.Eng.
Description:	Two X 4.0 MWth LNG Boilers and Two X 3.3 MWe LNG Cogeneration Units

Whitehorse Plant 2	Full Plant		Boiler Plant		LNG Cogen	
	Installed Capacity	**Totals** ($)	**Installed Capacity**	**Totals** ($)	**Installed Capacity**	**Totals** ($)
Hot Water						
Architectural/Civil/Structural	810 m2	$2,390,000	340 m2	$1,140,000	470 m2	$1,250,000
Electrical Installation	9,100 kVA	$2,570,000	500 kVA	$450,000	8,600 kVA	$2,120,000
Mechanical Installation	20.1 MWt	$3,610,000	14. MWt	$1,360,000	6.1 MWt	$2,250,000
Major Equipment (Blrs & Emerg Power)		$5,500,000		$850,000		$4,650,000
GC Admin, OH&P & PST		$1,770,000		$540,000		$1,230,000
Subtotal Construction		**$15,840,000**		**$4,340,000**		**$11,500,000**
Soft Costs						
Engineering		$2,030,000		$650,000		$1,380,000
Contingency		$1,580,000		$430,000		$1,150,000
Total		**$19,450,000**		**$5,420,000**		**$14,030,000**

Project:	WhiteHorse District Heating
Project #:	211313
Location:	Whitehorse, YT
Client:	Yukon Energy Corporation
Date:	29-Jun-12
Revision #:	1
Prepared by:	J Chin, P.Eng.
Reviewed by:	R.Doyle, P.Eng.
Description:	Plant 3 - 4 MW HW Boiler Plant - Oil Fired Only

Whitehorse Plant 3	**Boiler Plant**	
	Installed Capacity	**Totals** ($)
Hot Water		
Architectural/Civil/Structural/Utilites	140 m2	$367,000
Electrical Installation	250 kVA	$228,000
Mechanical Installation	4. MWt	$478,000
Major Equipment (Oil Blr)		$473,000
GC Admin, OH&P (No Taxes)		$208,000
Subtotal Construction		**$1,754,000**
Soft Costs		
Engineering		$377,000
Contingency		$175,000
Total		**$2,306,000**

D.4 Distribution Piping Capital Cost Assumptions

Distribution Piping System Capital Cost Assumptions

General Costing Assumptions

The cost estimates provide an opinion of probable cost based on normal competitive conditions from multiple contractors. The costing information and data contained herein represent FVB's best professional judgment in light of the knowledge and information available to FVB Energy Inc. at the time of preparation. The construction cost is based on local labour.

Detailed Costing Assumptions

1. Generally no trench boxes have been allowed for
2. Trench depth allows for 1200 mm cover to top of pipe
3. Cost per metre includes material supply, mechanical installation and civil works associated with community energy
4. Price includes for supply and return lines
5. Pricing assumes Series 2 Insulation
6. Mechanical and civil costs include allowance for mobilization, specialist, subcontractors, bonding and insurance
7. Cost estimate provided assumes competitive pricing
8. Off-site hauling has not been included
9. U-loops are assumed for expansion purposes
10. Inflation has not been included
11. Assume 10% of welds to be x-ray tested
12. If unknown, all service lines are assumed to be 10 metres in length, except for lots located more than 10 metres away from main
13. Assumes one 2" conduit to be used for communication from ETS's located in buildings
14. Estimate assumes that piping can be installed under existing Lewes Blvd bridge, as well as the existing Yukon river pedestrian bridge
15. The DPS costing also includes the allowance to cross Robert Service Way. This assumes an open trench that could close this roadway for approximately one week
16. Communication wiring included in cost
17. Welded isolation ball valves included in cost for each branch connection
18. Assumed LOGSTOR extra freight at 15% of piping material cost

Soft Cost Assumptions

- 10% Contractor OH&P is included
- 2.5% Administration, Bonding & Insurance is included
- 4% Construction Management and Supervision
- Price includes Engineering Design and Construction Support
- 10% Contingency is included

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Accuracy of Costing Assumptions

The cost estimates provided are Class 4 (as per AACE International No.17R-97) and thus are preliminary with a level of accuracy of +35% and –15%.

Exclusions

- Premium time (for off-hours work or an accelerated schedule).
- Cost of permitting.
- Owner's project development, marketing of service, and accounting costs.
- Owner's project management or onsite inspector/supervisor
- Third party QA/QC inspection
- Federal, provincial or municipal sales taxes.
- Erratic market conditions, such as lack of bidders.
- Escalation for deferred, phased or future works.

D.5 Distribution Piping System Capital Cost Summary

Project:	City of Whitehorse Study
Project #:	211313
Location:	Whitehorse, YK
Client:	YEC
Date:	May 28, 2012
Revision #:	0
Description:	Estimate is based on hydraulic model with 3 plants

Total		**Heating ($)**
Distribution Piping		
Mechanical - Material & Installation	8,700 m	$ 6,410,000
Civil - Excavation, Backfill & Reinstatement	8,700 m	$ 5,125,000
DPS Subtotal		**$ 11,535,000**
Construction Soft Costs		
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$ 1,441,000
Construction Management & Supervision	4.0%	$ 461,000
Goods & Services Tax	0.0%	$ -
Construction Soft Costs Subtotal		**$ 1,902,000**
Construction Total		**$ 13,437,000**
Owner's Soft Costs		
Engineering (Design & Construction Support)	varies	$ 1,286,000
Contingency (Design & Pricing)	10.0%	$ 1,343,000
Owner's Soft Costs Subtotal		**$ 2,629,000**
DPS Total		**$ 16,066,000**

Phase 1:		**Heating ($)**
Distribution Piping		
Mechanical - Material & Installation	1,770 m	$ 1,147,000
Civil - Excavation, Backfill & Reinstatement	1,770 m	$ 1,038,000
DPS Subtotal		**$ 2,185,000**
Construction Soft Costs		
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$ 273,000
Construction Management & Supervision	4%	$ 87,000
Goods & Services Tax	0%	$ -
Construction Soft Costs Subtotal		**$ 360,000**
Construction Total		**$ 2,545,000**
Owner's Soft Costs		
Engineering (Design & Construction Support)	9%	$ 229,000
Contingency (Design & Pricing)	10%	$ 255,000
Owner's Soft Costs Subtotal		**$ 484,000**
Phase 1 - DPS Total		**$ 3,029,000**

Phase 2:		Heating ($)
Distribution Piping		
Mechanical - Material & Installation	2,470 m	$ 2,454,000
Civil - Excavation, Backfill & Reinstatement	2,470 m	$ 1,445,000
DPS Subtotal		**$ 3,899,000**
Construction Soft Costs		
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$ 487,000
Construction Management & Supervision	4%	$ 156,000
Goods & Services Tax	0%	$ -
Construction Soft Costs Subtotal		**$ 643,000**
Construction Total		**$ 4,542,000**
Owner's Soft Costs		
Engineering (Design & Construction Support)	10%	$ 454,000
Contingency (Design & Pricing)	10%	$ 454,000
Owner's Soft Costs Subtotal		**$ 908,000**
Phase 2 - DPS Total		**$ 5,450,000**

Phase 3:		Heating ($)
Distribution Piping		
Mechanical - Material & Installation	1,905 m	$ 1,525,000
Civil - Excavation, Backfill & Reinstatement	1,905 m	$ 1,234,000
DPS Subtotal		**$ 2,759,000**
Construction Soft Costs		
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$ 345,000
Construction Management & Supervision	4%	$ 110,000
Goods & Services Tax	0%	$ -
Construction Soft Costs Subtotal		**$ 455,000**
Construction Total		**$ 3,214,000**
Owner's Soft Costs		
Engineering (Design & Construction Support)	10%	$ 321,000
Contingency (Design & Pricing)	10%	$ 321,000
Owner's Soft Costs Subtotal		**$ 642,000**
Phase 3 - DPS Total		**$ 3,856,000**

Phase 4:		Heating ($)	
Distribution Piping			
Mechanical - Material & Installation	1,600 m	$	846,000
Civil - Excavation, Backfill & Reinstatement	1,600 m	$	918,000
DPS Subtotal		**$**	**1,764,000**
Construction Soft Costs			
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$	220,000
Construction Management & Supervision	4%	$	71,000
Goods & Services Tax	0%	$	-
Construction Soft Costs Subtotal		**$**	**291,000**
Construction Total		**$**	**2,055,000**
Owner's Soft Costs			
Engineering (Design & Construction Support)	9%	$	185,000
Contingency (Design & Pricing)	10%	$	205,000
Owner's Soft Costs Subtotal		**$**	**390,000**
Phase 4 - DPS Total		**$**	**2,445,000**

Phase 5:		Heating ($)	
Distribution Piping			
Mechanical - Material & Installation	960 m	$	438,000
Civil - Excavation, Backfill & Reinstatement	960 m	$	490,000
DPS Subtotal		**$**	**928,000**
Construction Soft Costs			
Contractor Admin., Bonding, Insurance & OH&P	12.5%	$	116,000
Construction Management & Supervision	4%	$	37,000
Goods & Services Tax	0%	$	-
Construction Soft Costs Subtotal		**$**	**153,000**
Construction Total		**$**	**1,081,000**
Owner's Soft Costs			
Engineering (Design & Construction Support)	9%	$	97,000
Contingency (Design & Pricing)	10%	$	108,000
Owner's Soft Costs Subtotal		**$**	**205,000**
Phase 5 - DPS Total		**$**	**1,286,000**

D.6 Energy Transfer Station Capital Cost Assumptions

Energy Transfer Station Capital Cost Assumptions

General Costing Assumptions

The cost estimates provide an opinion of probable cost based on normal competitive conditions from multiple contractors. The costing information and data contained herein represent FVB's best professional judgment in light of the knowledge and information available to FVB Energy Inc. at the time of preparation. The costs are representative for the design and construction of multiple Energy Transfer Stations (minimum of four) in the same phase of work. The construction cost is based on local labour.

Detailed Costing Assumptions

- One ETS per building
- ETS cost reflects an in-direct connection based on 115°C district heating supply temperature
- Typically pricing reflects one heat exchanger sized for 120% of peak heating demand for heating and one heat exchanger for 100% of the DHW load.
- Two heat exchangers are assumed for each hospital system connection with an overall redundancy of capacity of 40%
- Pricing is based on calculated peak loads for heating as shown in the load table.
- ETS Costs include primary side piping, equipment and instrumentation with typically 15% additional cost added for internal piping to reach mechanical rooms and to include building secondary system modifications
- Typically pricing assumes sufficient floor space in a ground or basement level mechanical room and limits the ETS location to a maximum of 10 metres from an outside wall
- Pricing reflects a combined commercial grade control system and thermal metering
- Pricing reflects all primary side and a set of main secondary isolation valves.
- Communication cable, material and installation from mainline in street to building wall not included in pricing. These costs are carried in the DPS pricing
- No domestic hot water connection allowed for in small office buildings
- Building heating system assumed as glycol mixture unless specifically noted in building survey
- Costs of modifications for supplemental heating of high temperature DHW at hospital has not been allowed for

Soft Cost Assumptions

- 10% Contractor OH&P is included
- 4% Construction Management and Supervision
- 16% is included for Engineering Design and Construction Support
- 10% Contingency is included

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Accuracy of Costing Assumptions

- The cost estimates provided are Class 4 (as per AACE International No.17R-97) and thus are preliminary with a level of accuracy of +35% and –15%.

Exclusions

- Premium time (for off-hours work or an accelerated schedule).
- Asbestos or other hazardous material abatement.
- Removal of existing equipment.
- Cost of permitting.
- Owner’s project development, marketing of service, and accounting costs.
- Owner’s project management or onsite inspector/supervisor
- Commissioning of system
- Third party QA/QC inspection
- LEED Accreditation/certifications.
- Federal, provincial or municipal sales taxes.
- Erratic market conditions, such as lack of bidders.
- Escalation for deferred, phased or future works.

D.7 Energy Transfer Station Capital Cost Summary

Project:	City of Whitehorse Study
Project #:	211313
Location:	Yukon
Client:	YEC
Date:	June 20, 2012
Revision #:	1
Prepared by:	D. Doherty
Reviewed by:	S.Wolter
Model #:	7
Data Source:	FVB Database
Description:	Preliminary Whitehorse ETS Costs

City of Whitehorse Study - Total ETS Cost Estimate ***All Phases***		**Heating ($)**
21000 kW of Heating (43 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$1,301,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$3,459,000
Contractor Supplied Subtotal		**$3,459,000**
Conversion Costs - Additional Secondary Piping & Modifications		$729,000
		$729,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$220,000
Goods & Services Tax	0%	$0
Subtotal Construction Soft Costs		**$220,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$914,000
Contingency	10%	$571,000
Subtotal Owner's Soft Costs		**$1,485,000**
Total ETS Cost (w/o Taxes)		**$7,194,000**
Total ETS Cost (w/ Taxes)		**$7,194,000**

City of Whitehorse Study - ETS Cost Estimate *Phase 1*		Heating ($)
6049 kW of Heating (6 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$241,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$561,000
Contractor Supplied Subtotal		**$561,000**
Conversion Costs - Additional Secondary Piping & Modifications		$120,000
		$120,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$37,000
Goods & Services Tax	0%	$0
Subtotal Construction		**$37,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$154,000
Contingency	10%	$96,000
Subtotal Owner's Soft Costs		**$250,000**
Total ETS Cost (w/o Taxes)		**$1,209,000**
Total ETS Cost (w/ Taxes)		**$1,209,000**

City of Whitehorse Study - ETS Cost Estimate *Phase 2*		Heating ($)
1520 kW of Heating (4 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$107,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$316,000
Contractor Supplied Subtotal		**$316,000**
Conversion Costs - Additional Secondary Piping & Modifications		$64,000
		$64,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$19,000
Goods & Services Tax	0%	$0
Subtotal Construction		**$19,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$81,000
Contingency	10%	$51,000
Subtotal Owner's Soft Costs		**$132,000**
Total ETS Cost (w/o Taxes)		**$638,000**
Total ETS Cost (w/ Taxes)		**$638,000**

City of Whitehorse Study - ETS Cost Estimate *Phase 3*		Heating ($)
4869 kW of Heating (12 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$341,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$933,000
Contractor Supplied Subtotal		**$933,000**
Conversion Costs - Additional Secondary Piping & Modifications		$195,000
		$195,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$59,000
Goods & Services Tax	0%	$0
Subtotal Construction		**$59,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$244,000
Contingency	10%	$153,000
Subtotal Owner's Soft Costs		**$397,000**
Total ETS Cost (w/o Taxes)		**$1,925,000**
Total ETS Cost (w/ Taxes)		**$1,925,000**

City of Whitehorse Study - ETS Cost Estimate *Phase 4*		Heating ($)
5410 kW of Heating (13 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$377,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$1,021,000
Contractor Supplied Subtotal		**$1,021,000**
Conversion Costs - Additional Secondary Piping & Modifications		$218,000
		$218,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$65,000
Provincial Sales Tax	0%	$0
Goods & Services Tax	0%	$0
Harmonized Sales Tax	0%	$0
Subtotal Construction		**$65,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$269,000
Contingency	10%	$168,000
Subtotal Owner's Soft Costs		**$437,000**
Total ETS Cost (w/o Taxes)		**$2,118,000**
Total ETS Cost (w/ Taxes)		**$2,118,000**

City of Whitehorse Study - ETS Cost Estimate *Phase 5*		Heating ($)
2954 kW of Heating (8 Heating ETS's)		
Major Equipment (Material only - Typically Owner Supplied)		
Major Equipment Subtotal		**$235,000**
Contractor Supplied (Material & Labour)		
Mechanical & Electrical Material and Installation		$628,000
Contractor Supplied Subtotal		**$628,000**
Conversion Costs - Additional Secondary Piping & Modifications		$132,000
		$132,000
Construction Soft Costs		
General Contractor Overhead and Profit		Included
Construction Management and Supervision	4%	$40,000
Goods & Services Tax	0%	$0
Subtotal Construction		**$40,000**
Owner's Soft Costs		
Engineering (Design, Construction and Commissioning Support)	16%	$166,000
Contingency	10%	$104,000
Subtotal Owner's Soft Costs		**$270,000**
Total ETS Cost (w/o Taxes)		**$1,305,000**
Total ETS Cost (w/ Taxes)		**$1,305,000**

Notes:

1. ETS Costs reflects primary side with secondary side modification included.
2. Pricing assumes sufficient floor space in a ground or basement level mechanical room and limits the ETS location to maximum of 10 m. from an outside wall.
3. The cost estimates provided are Class C and thus are preliminary.
4. Pricing reflects 1 heat exchanger at 120% for heating and 1 heat exchanger for DHW.
5. Pricing reflects a combined commercial control system and metering.
6. ETS Cost reflects an in-direct connection based on 120°C district heating supply temperature.
7. Pricing is based on calculated peak loads for heating as shown in the load table.
8. Communication cable, material and installation from mainline in street to building wall not included in pricing. These costs are carried in the DPS pricing.
9. No domestic hot water connection allowed for in small office buildings.
10. Building heating system assumed as glycol mixture unless specifically noted in builidng survey.
11. Additional Heat exchanger redundancy capacity of 40% allowed for at the hospital over 2 units for each system.
12. Connection cost of high temperature DHW at hospital has not been allowed for.
13. 15% additional cost has been added for internal piping to reach mechanical rooms and building secondary system modifications.

Appendix E - Operation and Maintenance Summary

E.1 Biomass Concept O&M Summary

Phased Operation - July 6, 2012 Rev 3 Two - 3.5 MWth Combustor & ORC	Phase 1	Phase 2	Phase 3	Phase 4	Full Buildout
Loads: Current Building Standards					
Contract Load	4.80 MW	6.10 MW	10.20 MW	14.70 MW	17.20 MW
Diversified Load	4.08 MW	5.19 MW	8.67 MW	12.50 MW	14.62 MW
Displaced Heating Energy	12,580 MWh	16,120 MWh	24,870 MWh	35,450 MWh	41,100 MWh
DH Temps (peak/non-peak) deg C	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60
Hot Water Production					
Plant #1 Fuel Oil Boiler Unit(s)	1	1	1	1	1
Plant #1 Fuel Oil Boiler Size	4.0 MW	4.0 MW	4.0 MW	4.0 MW	4.0 MW
Plant #2 Fuel Oil Boiler Unit(s)		1	2	2	2
Plant #2 Fuel Oil Boiler Size		4.0 MW	4.0 MW	4.0 MW	4.0 MW
Plant #3 Fuel Oil Boiler Unit(s)				1	1
Plant #3 Fuel Oil Boiler Size				4.0 MW	4.0 MW
# of Units	1	2	3	4	4
Total Peaking/BU Fuel Oil Boilers Capacity	4.0 MW	8.0 MW	12.0 MW	16.0 MW	16.0 MW
Plant #2 - Alt Heating Unit	Biomass Boiler with ORC	Biomass Boiler with ORC	Biomass Boiler with ORC	Biomass Boiler with ORC	Biomass Boiler with ORC
Alt Heating Energy source	Wood Chips (25% MC)	Wood Chips (25% MC)	Wood Chips (25% MC)	Wood Chips (25% MC)	Wood Chips (25% MC)
# of Units		1	2	2	2
Alternate Thermal Heating Unit Size		3.5 MW	3.5 MW	3.0 MW	3.0 MW
Total Alternate Thermal Output Capacity	0.0 MW	3.5 MW	7.0 MW	6.0 MW	6.0 MW
Total Capacity	4.0 MW	11.5 MW	19.0 MW	22.0 MW	22.0 MW
Total "N-1" Capacity		7.5	15.0 MW	18.0 MW	18.0 MW
Redundancy		144.6%	173.0%	144.1%	123.1%
Total Plant Site Footprint	30 sq m	840 sq m	840 sq m	980 sq m	980 sq m
Electrical Production					
Reciprocating Engine / ORC				1.21 MWe	1.21 MWe
Cogen / ORC Run Hours				7,088 hours	7,056 hours
ORC Electrical Load Factor				73%	79%
Sources of Energy					
Thermal Energy from P1 Fuel Oil Peaking Boilers	12,580 MWh	680 MWh	40 MWh		
Thermal Energy from P2 Fuel Oil Peaking Boilers		1,300 MWh	1,360 MWh	3,560 MWh	6,070 MWh
Thermal Energy from Alt Heating Hot Oil System		14,140 MWh	23,470 MWh	2,630 MWh	3,440 MWh
Thermal Energy from ORC Thermal Exchange				29,260 MWh	31,590 MWh
Thermal Energy from P3 Fuel Oil Back-Up Boilers					
Total Supplied Thermal Energy	12,580 MWh	16,120 MWh	24,870 MWh	35,450 MWh	41,100 MWh
Annual Biomass Consumption		4,510 Tonnes	7,490 Tonnes	12,330 Tonnes	13,500 Tonnes
Annual Fuel Oil Consumption	1,454,900 L	229,000 L	161,900 L	411,700 L	702,100 L
Equipment Efficiencies (Avg Life Cycle)					
Fuel Oil Peaking/BU Boilers SBE	80%	80%	80%	80%	80%
Heating - Alternate Capacity SBE	73%	73%	73%	73%	73%
Heating - ORC Thermal Efficiency				81%	81%
Fuel Consumption					
Fuel Oil - Peaking/BU Heating	56,610 GJ	8,910 GJ	6,300 GJ	16,020 GJ	27,320 GJ
Biomass [GJ]		69,700 GJ	115,700 GJ	190,500 GJ	208,600 GJ
Biomass MC	25%	25%	25%	25%	25%
Biomass HHV	15.5 MJ/kg	15.5 MJ/kg	15.5 MJ/kg	15.5 MJ/kg	15.5 MJ/kg
Alternate Heating Biomass Consumption		4,510 Tonnes	7,490 Tonnes	12,330 Tonnes	13,500 Tonnes
Total Fuel Required	56,610 GJ	78,610 GJ	122,000 GJ	206,520 GJ	235,920 GJ
Electrical Production					
Cogen Electricity Produced				6,110 MWh(e)	6,690 MWh(e)
Electricity sales				$916,500	$1,003,500
Capital Costs					
P1 Hospital Connection	$1,171,000				
P2 Fuel Oil Boiler Plant		$4,974,000	$579,000		
P2 Biomass Plant		$9,855,000	$4,188,000		
P2 ORC				$4,705,000	
P3 Fuel Oil Boiler Plant				$2,306,000	
Total Plant Capital	$1,171,000	$14,829,000	$4,767,000	$7,011,000	$0
DPS Capital	$3,029,000	$5,450,000	$3,856,000	$2,445,000	$1,286,000
ETS Capital	$1,209,000	$638,000	$1,925,000	$2,118,000	$1,305,000
Total Capital Cost	$5,409,000	$20,917,000	$10,548,000	$11,574,000	$2,591,000
					$51,039,000

1) Biomass HHV: 15.5 GJ/Tonne @ 25% Moisture Content
2) Fuel Oil HHV: 10.8 kWh/L

PROJECT NAME:	Whitehorse DE
CLIENT:	YEC
PROJECT No.	211313
PREPARED BY:	John Chin
DATA SOURCE:	FVB Data Base
REVISION No.	3
REVISION DATE:	06-Jul-12
SHEET:	O&M Cost Summary
	Two - 3.5 MW_{th} Combustor & ORC

	Phase 1	**Phase 2**	**Phase 3**	**Phase 4**	**Full Buildout**
Fuel					
Peaking & Back-Up Boiler(s) - Fuel Oil Consumption	1,450,000 Litres	230,000 Litres	160,000 Litres	410,000 Litres	700,000 Litres
Boiler Fuel Cost - Oil: (@ $1.00/L)	$1,455,000	$229,000	$162,000	$412,000	$702,000
Biomass Wood Chip Fuel Consumption (Green Tonnes)	0 tonnes	4,500 tonnes	7,500 tonnes	12,300 tonnes	13,500 tonnes
Biomass Wood Chip Fuel Consumption (ODT)	0 tonnes	3,400 tonnes	5,600 tonnes	9,200 tonnes	10,100 tonnes
Biomass Fuel Cost: (@ $150 /Green Tonne)	$0	$677,000	$1,124,000	$1,849,000	$2,025,000
Biomass Produced Ash	0 tonnes	170 tonnes	280 tonnes	460 tonnes	510 tonnes
Ash Removal Cost: (@ $40 /Tonne)	$0	$7,000	$11,000	$18,000	$20,000
Total Annual Fuel Cost	$1,455,000	$913,000	$1,297,000	$2,279,000	$2,747,000
Electricity Consumption					
Plant Internal Power Consumption	63,400 kWh	838,400 kWh	1,433,100 kWh	2,049,000 kWh	2,115,800 kWh
Electricity Purchase Cost: (@ $0.1457 /kWhr)	$9,000	$122,000	$209,000	$299,000	$308,000
Total Annual Electricity Consumption Cost	$9,000	$122,000	$209,000	$299,000	$308,000
Electricity Sales					
Total Electrical Production	0 MWhe	0 MWhe	0 MWhe	6,100 MWhe	6,700 MWhe
Electricity Sales Price: (@ $0.1500 /kWhr)	$0	$0	$0	$917,000	$1,004,000
Total Annual Electricity Sales	$0	$0	-$0	-$917,000	-$1,004,000
Makeup Water					
Makeup Water Volume	900 m3	1,200 m3	2,000 m3	5,300 m3	5,500 m3
Blended Water & Sewer: (@ $1.68 /m3)	$2,000	$2,000	$3,000	$9,000	$9,000
Water Treatment	$3,000	$3,000	$5,000	$8,000	$10,000
Total Annual Makeup Water Cost	$5,000	$5,000	$8,000	$17,000	$19,000
Operating and Maintenance					
P1 O&M	$6,000	$6,000	$6,000	$6,000	$6,000
P2 Heating Equipment O&M (2) (3)	$0	$50,000	$56,000	$56,000	$56,000
P2 Biomass Equipment O&M	$0	$99,000	$140,000	$140,000	$140,000
P2 ORC Equipment O&M	$0	$0	$0	$43,000	$45,000
P3 O&M	$0	$0	$0	$23,000	$23,000
ETS Maintenance (3)	$6,000	$9,000	$19,000	$29,000	$36,000
Piping Maintenance (3)	$11,000	$30,000	$43,000	$52,000	$56,000
Total Annual Operating and Maintenance Cost	$23,000	$194,000	$264,000	$349,000	$362,000
Administration and Personnel					
Insurance	$9,000	$120,000	$156,000	$208,000	$208,000
Office & Administration Costs (4)	$53,000	$163,000	$190,000	$219,000	$225,000
Operating Labour & Supervision Staff Requirements (1)	2	5	5	5	5
Total Annual Administration and Personnel Cost	$218,000	$673,000	$736,000	$817,000	$823,000
Total Operating Cost	**$1,710,000**	**$1,907,000**	**$2,514,000**	**$2,844,000**	**$3,255,000**

1) Generally operating staff are assumed to be capable of performing general maintenance & house keeping duties.
2) This line item is intended to cover equipment replacement, repair, & outside services. Outside services are assumed to be provided for specialists such as millwrights for pump alignments, pipe fitting, boiler technicians for boiler combustion testing and tuning, insulation, etc.
3) In the early years of operation a portion of these costs should be dedicated to a sinking fund to cover such things as motor rebuilds, boiler tube replacements, refractory replacement, valves replacement etc.
4) This line item is intended to cover such items as legal, accounting, phones, taxes, admin, office supplies, etc.
5) This option captures all the engine fuel costs and all available waste heat to be recovered.

E.2 LNG Concept O&M Summary

Phased Operation - July 20, 2012 Rev 1 **Two - 3.05 MWth LNG Cogen Engines**	**Phase 1**	**Phase 2**	**Phase 3**	**Phase 4**	**Full Buildout**
Loads: Current Building Standards					
Contract Load	4.80 MW	6.10 MW	10.20 MW	14.70 MW	17.20 MW
Diversified Load	4.08 MW	5.19 MW	8.67 MW	12.50 MW	14.62 MW
Displaced Heating Energy	12,580 MWh	16,120 MWh	24,870 MWh	35,450 MWh	41,100 MWh
DH Temps (peak/non-peak) deg C	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60	S - 120 / 75; R - 80 / 60
Hot Water Production					
Plant #1 Hot Water Conversion Unit(s)	1	1	1	1	1
Plant #1 Hospital Connection Size	4.0 MW	4.0 MW	4.0 MW	4.0 MW	4.0 MW
Plant #2 LNG Boiler Unit(s)			1	2	2
Plant #2 LNG Boiler Size			4.0 MW	4.0 MW	4.0 MW
Plant #3 Fuel Oil Boiler Unit(s)				1	1
Plant #3 Fuel Oil Boiler Size				4.0 MW	4.0 MW
# of Units	1	1	2	4	4
Total Peaking/BU LNG Boilers Capacity	4.0 MW	4.0 MW	8.0 MW	16.0 MW	16.0 MW
Plant #2 - Alt Heating Unit	Engine CHP	Engine CHP	Engine CHP	Engine CHP	Engine CHP
Alt Heating Energy source	LNG	LNG	LNG	LNG	LNG
# of Units		2	2	2	2
Alternate Thermal Heating Unit Size		3.0 MW	3.0 MW	3.0 MW	3.0 MW
Total Alternate Thermal Output Capacity	0.0 MW	6.1 MW	6.1 MW	6.1 MW	6.1 MW
Total Capacity	4.0 MW	10.1 MW	14.1 MW	22.1 MW	22.1 MW
Total "N-1" Capacity		6.1	10.1 MW	18.1 MW	18.1 MW
Redundancy		117.6%	116.5%	144.9%	123.8%
Total Plant Site Footprint	30 sq m	780 sq m	780 sq m	920 sq m	920 sq m
Electrical Production					
Reciprocating Engine		6.61 MWe	6.61 MWe	6.61 MWe	6.61 MWe
Cogen Run Hours		4,893 hours	4,893 hours	4,893 hours	4,893 hours
Thermal Heat Recovery from Cogen		41.1%	63.5%	83.4%	89.2%
Sources of Energy					
Thermal Energy from P1 Fuel Oil Hot Water Conversion	12,580 MWh	3,848 MWh	34 MWh		11 MWh
Thermal Energy from P2 LNG Peaking Boilers			5,903 MWh	10,556 MWh	14,465 MWh
Thermal Energy from Cogen Heat Recovery		12,272 MWh	18,933 MWh	24,894 MWh	26,624 MWh
Thermal Energy from P3 Fuel Oil Back-Up Boilers					
Total Supplied Thermal Energy	12,580 MWh	16,120 MWh	24,870 MWh	35,450 MWh	41,100 MWh
Equipment Efficiencies (Avg Life Cycle)					
Fuel Oil Peaking/BU Boilers SBE	80.0%	80.0%	80.0%	80.0%	80.0%
LNG Peaking/BU Boilers SBE	78.5%	78.5%	78.5%	78.5%	78.5%
Cogen Thermal Efficiency (LHV)	41.5%	41.5%	41.5%	41.5%	41.5%
Cogen Electrical Efficiency (LHV)	45.2%	45.2%	45.2%	45.2%	45.2%
Fuel Consumption					
Fuel Oil - Peaking/BU Heating	56,610 GJ	17,320 GJ	150 GJ		50 GJ
LNG - Peaking/BU Heating			27,070 GJ	48,410 GJ	66,340 GJ
LNG - Cogen Engine(s) [GJ]		285,920 GJ	285,920 GJ	285,920 GJ	285,920 GJ
Total Fuel Required	56,610 GJ	303,240 GJ	313,140 GJ	334,330 GJ	352,310 GJ
Annual Fuel Oil Consumption	1,454,900 L	445,100 L	3,900 L		1,300 L
Annual LNG Consumption		7,564,000 m3	8,280,200 m3	8,844,700 m3	9,319,000 m3
Electrical Production					
Cogen Electricity Produced		32,340 MWh(e)	32,340 MWh(e)	32,340 MWh(e)	32,340 MWh(e)
Electricity sales		$4,851,300	$4,851,300	$4,851,300	$4,851,300
Capital Costs					
P1 Hospital Connection	$1,171,000				
P2 LNG Boiler Plant			$4,655,000	$579,000	
P2 Cogen Units		$15,278,000			
P3 Fuel Oil Boiler Plant				$2,306,000	
Total Plant Capital	$1,171,000	$15,278,000	$4,655,000	$2,885,000	$0
DPS Capital	$3,029,000	$5,450,000	$3,856,000	$2,445,000	$1,286,000
ETS Capital	$1,209,000	$638,000	$1,925,000	$2,118,000	$1,305,000
Total Capital Cost	$5,409,000	$21,366,000	$10,436,000	$7,448,000	$2,591,000
					$47,250,000

1) Fuel Oil HHV: 38.9 MJ/L
2) LNG HHV: 10.5 kWh/m3

PROJECT NAME:	Whitehorse DE - LNG Concept
CLIENT:	YEC
PROJECT No.	211313
PREPARED BY:	Gary Saskiw
DATA SOURCE:	FVB Data Base
REVISION No.	1
REVISION DATE:	24-Jul-12
SHEET:	O&M Cost Summary
	Two - 3.05 MW_{th} LNG Cogen Engines

	Phase 1	Phase 2	Phase 3	Phase 4	Full Buildout
Fuel					
Peaking & Back-Up Boiler(s) - Fuel Oil Consumption	1,455,000 L	445,000 L	4,000 L	0 L	1,000 L
HW Conversrion Fuel Cost - Fuel Oil: (@ $1.00/L)	$1,455,000	$445,000	$4,000	$0	$1,000
Peaking & Back-Up Boiler(s) - LNG Consumption	0 m3	0 m3	716,000 m3	1,281,000 m3	1,755,000 m3
Boiler Fuel Cost - LNG: (@ $15.00/GJ)	$0	$0	$406,000	$726,000	$995,000
Cogen Engine(s) - LNG Consumption	0 m3	7,564,000 m3	7,564,000 m3	7,564,000 m3	7,564,000 m3
Cogen Fuel Cost - LNG: (@ $15.00/GJ)	$0	$4,289,000	$4,289,000	$4,289,000	$4,289,000
Total Annual Fuel Cost	$1,455,000	$4,734,000	$4,699,000	$5,015,000	$5,285,000
Electricity Consumption					
Plant Internal Power Consumption	56,800 kWh	859,300 kWh	744,400 kWh	719,900 kWh	689,900 kWh
Electricity Purchase Cost: (@ $0.1457 /kWhr)	$8,000	$125,000	$108,000	$105,000	$101,000
Total Annual Electricity Consumption Cost	$8,000	$125,000	$108,000	$105,000	$101,000
Electricity Sales					
Total Electrical Production	0 MWhe	32,300 MWhe	32,300 MWhe	32,300 MWhe	32,300 MWhe
Electricity Sales Price: (@ $0.1500 /kWhr)	$0	$4,851,000	$4,851,000	$4,851,000	$4,851,000
Total Annual Electricity Sales	$0	-$4,851,000	-$4,851,000	-$4,851,000	-$4,851,000
Makeup Water					
Makeup Water Volume	400 m3	500 m3	800 m3	1,200 m3	1,400 m3
Blended Water & Sewer: (@ $1.68 /m3)	$1,000	$1,000	$1,000	$2,000	$2,000
Water Treatment	$3,000	$10,000	$11,000	$14,000	$15,000
Total Annual Makeup Water Cost	$4,000	$11,000	$12,000	$16,000	$17,000
Operating and Maintenance					
P1 O&M	$6,000	$6,000	$6,000	$6,000	$6,000
P2 Heating Equipment O&M (2) (3)	$0	$0	$52,000	$52,000	$52,000
P2 Cogen Equipment O&M	$0	$76,000	$76,000	$76,000	$76,000
P2 Cogen O&M	$0	$387,000	$387,000	$387,000	$387,000
P3 O&M	$0	$0	$23,000	$23,000	$23,000
ETS Maintenance (3)	$6,000	$9,000	$29,000	$29,000	$36,000
Piping Maintenance (3)	$11,000	$30,000	$52,000	$52,000	$56,000
Total Annual Operating and Maintenance Cost	$23,000	$508,000	$625,000	$625,000	$636,000
Administration and Personnel					
Insurance	$9,000	$123,000	$180,000	$180,000	$180,000
Office & Administration Costs (4)	$53,000	$164,000	$209,000	$209,000	$216,000
Operating Labour & Supervision Staff Requirements (1)	2	5	5	5	5
Total Annual Administration and Personnel Cost	$218,000	$677,000	$779,000	$779,000	$786,000
	$1,708,000	**$1,204,000**	**$1,372,000**	**$1,689,000**	**$1,974,000**

1) Generally operating staff are assumed to be capable of performing general maintenance & house keeping duties.
2) This line item is intended to cover equipment replacement, repair, & outside services. Outside services are assumed to be provided for specialists such as millwrights for pump alignments, pipe fitting, boiler technicians for boiler combustion testing and tuning, insulation, etc.
3) In the early years of operation a portion of these costs should be dedicated to a sinking fund to cover such things as motor rebuilds, boiler tube replacements, refractory replacement, valves replacement etc.
4) This line item is intended to cover such items as legal, accounting, phones, taxes, admin, office supplies, etc.
5) This option captures all the engine fuel costs and all available waste heat to be recovered.

Appendix F - Business As Usual

F.1 Self Generation Annual Cost Assumption

Self-Generation Annual Cost Assumptions

Fuel Cost:

- Propane cost at $30.70 per GJ (delivered) for government buildings
- Heating Oil #1 and # 2 at $1.00 per Litre for government buildings
- Heating Oil #1 and # 2 at $1.30 per Litre for non-government buildings

The lifetime seasonal boiler plant efficiency ranges between 60% to 75% for different buildings. It is based on assumed installed equipment and accounts for partial and full load use and the degradation of performance over the life of the equipment.

Electricity Cost:

The electricity cost associated with the boiler plant only. The electricity cost was set at $0.146/kWh$_e$.

Water Treatment Supplies, Water, Parts and Sewer Cost:

This includes the cost of the water and water treatment chemicals and running the equipment associated with the treating process for the boiler system, including discharge to the sewer.

Boiler Insurance Cost:

Since boilers would no longer be in use, the owner would save on boiler insurance.

Equipment Maintenance Cost:

The maintenance costs were based on RSMeans Costworks Maintenance and Repair Costs for 2012. Yearly preventive costs were added to repair and maintenance costs that occur typically every 7 years for oil boilers.

Labour Cost:

Fired boilers require operator attention in order to maintain safe and reliable operation. The labour cost for a portion of one person's effort as a facility operator (or maintenance contractor) was estimated based on an annual labour rate of $ 78,000.

Administration & Management Cost:

Administration and management costs are real costs associated with boiler budgeting and cost control, equipment maintenance contract negotiation, and ongoing planning and coordination.

Capital Replacement Cost:

By connecting to the CES, boiler installations are not required. It was assumed that heating equipment would need to be replaced every 25 years. An interest rate of 6.2% was used to calculate the amortized cost.

Appendix G- Business Case

G.1 Income Statements

FVB Energy Inc: Two 3.5 MW Combustor with ORC

Exhibit: Income Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Revenue																										
Capacity Charge	-	988	1,008	1,307	1,334	2,272	2,318	3,409	3,477	4,148	4,231	4,315	4,402	4,490	4,579	4,671	4,764	4,860	4,957	5,056	5,157	5,260	5,366	5,473	5,582	5,694
Consumption Charge	-	819	835	1,084	1,105	1,884	1,921	2,825	2,882	3,438	3,507	3,577	3,648	3,721	3,796	3,872	3,949	4,028	4,109	4,191	4,275	4,360	4,447	4,536	4,627	4,720
Electric Sales	-	-	-	-	-	-	-	1,030	1,051	1,178	1,201	1,225	1,250	1,275	1,300	1,326	1,353	1,380	1,407	1,435	1,464	1,493	1,523	1,554	1,585	1,616
Total revenue	-	1,807	1,843	2,391	2,439	4,156	4,239	7,264	7,410	8,763	8,939	9,117	9,300	9,486	9,675	9,869	10,066	10,268	10,473	10,682	10,896	11,114	11,336	11,563	11,794	12,030
Operating Cost																										
Variable costs	-	1,923	1,962	833	850	1,448	1,477	2,425	2,182	2,597	2,649	2,702	2,756	3,000	3,060	3,121	3,184	3,247	3,551	3,622	3,694	3,768	3,843	3,920	3,999	4,079
Fixed costs	-	226	358	718	797	865	956	1,032	1,065	1,095	1,112	1,129	1,146	1,164	1,182	1,201	1,220	1,239	1,259	1,279	1,300	1,320	1,342	1,364	1,386	1,408
Total operating cost	-	2,149	2,320	1,551	1,647	2,314	2,433	3,456	3,247	3,692	3,760	3,830	3,902	4,164	4,242	4,322	4,404	4,487	4,810	4,901	4,994	5,088	5,185	5,284	5,384	5,487
EBITDA	-	(343)	(477)	840	792	1,842	1,806	3,808	4,163	5,071	5,178	5,287	5,398	5,321	5,433	5,547	5,663	5,781	5,663	5,782	5,902	6,025	6,151	6,279	6,410	6,543
EBITDA %		*-19%*	*-26%*	*35%*	*32%*	*44%*	*43%*	*52%*	*56%*	*58%*	*58%*	*58%*	*58%*	*56%*	*56%*	*56%*	*56%*	*56%*	*54%*	*54%*	*54%*	*54%*	*54%*	*54%*	*54%*	*54%*
Depreciation & Amortisation	-	216	216	1,053	1,053	1,475	1,475	1,939	1,939	2,044	2,045	2,046	2,048	2,049	2,052	2,054	2,056	2,059	2,061	2,063	2,066	2,069	2,071	2,074	2,077	2,079
EBIT	-	(559)	(693)	(213)	(261)	367	331	1,869	2,223	3,028	3,133	3,241	3,350	3,272	3,381	3,493	3,606	3,722	3,602	3,718	3,836	3,957	4,080	4,205	4,333	4,464
Interest cost	-	154	154	749	731	1,002	966	1,254	1,205	1,224	1,167	1,109	1,050	992	934	876	817	759	701	642	584	526	467	409	351	293
EBT	-	(713)	(848)	(962)	(991)	(634)	(635)	615	1,018	1,804	1,966	2,132	2,300	2,280	2,448	2,617	2,789	2,963	2,902	3,076	3,252	3,431	3,612	3,796	3,982	4,171
Net profit	-	(713)	(848)	(962)	(991)	(634)	(635)	615	1,018	1,804	1,966	2,132	2,300	2,280	2,448	2,617	2,789	2,963	2,902	3,076	3,252	3,431	3,612	3,796	3,982	4,171
Net profit %	*0%*	*-39%*	*-46%*	*-40%*	*-41%*	*-15%*	*-15%*	*8%*	*14%*	*21%*	*22%*	*23%*	*25%*	*24%*	*25%*	*27%*	*28%*	*29%*	*28%*	*29%*	*30%*	*31%*	*32%*	*33%*	*34%*	*35%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	-	(713)	(848)	(962)	(991)	(634)	(635)	615	1,018	1,804	1,966	2,132	2,300	2,280	2,448	2,617	2,789	2,963	2,902	3,076	3,252	3,431	3,612	3,796	3,982	4,171
Cash profit	-	(497)	(632)	91	62	841	841	2,554	2,957	3,848	4,011	4,178	4,347	4,329	4,499	4,671	4,845	5,022	4,963	5,139	5,318	5,500	5,684	5,870	6,059	6,250

Model run for

Capacity charge (CAD/kW/month) = 19.78, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.7%   Equity IRR for this option: 8.8%

FVB Energy Inc: 7.0 MW Combustor with ORC

Exhibit: Income Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Revenue																										
Capacity Charge	-	1,153	1,176	1,526	1,557	2,652	2,705	3,978	4,058	4,841	4,938	5,037	5,137	5,240	5,345	5,452	5,561	5,672	5,786	5,901	6,019	6,140	6,262	6,388	6,515	6,646
Consumption Charge	-	819	835	1,084	1,105	1,884	1,921	2,825	2,882	3,438	3,507	3,577	3,648	3,721	3,796	3,872	3,949	4,028	4,109	4,191	4,275	4,360	4,447	4,536	4,627	4,720
Electric Sales	-	-	-	-	-	-	-	1,030	1,051	1,178	1,201	1,225	1,250	1,275	1,300	1,326	1,353	1,380	1,407	1,435	1,464	1,493	1,523	1,554	1,585	1,616
Total revenue	-	1,972	2,011	2,610	2,662	4,536	4,627	7,834	7,991	9,457	9,646	9,839	10,035	10,236	10,441	10,650	10,863	11,080	11,302	11,528	11,758	11,993	12,233	12,478	12,727	12,982
Operating Cost																										
Variable costs	-	1,923	1,962	2,031	2,071	3,621	3,693	5,431	2,805	3,339	3,406	3,474	3,543	3,222	3,287	3,353	3,420	3,488	3,746	3,821	3,897	3,975	4,055	4,136	4,218	4,303
Fixed costs	-	226	298	605	726	830	920	996	1,029	1,058	1,075	1,091	1,108	1,126	1,143	1,161	1,180	1,199	1,218	1,238	1,258	1,278	1,299	1,320	1,342	1,364
Total operating cost	-	2,149	2,260	2,636	2,797	4,451	4,613	6,427	3,834	4,397	4,480	4,565	4,652	4,348	4,430	4,514	4,600	4,687	4,964	5,058	5,155	5,253	5,353	5,456	5,560	5,666
EBITDA	-	(178)	(248)	(26)	(136)	85	13	1,407	4,157	5,059	5,165	5,274	5,384	5,888	6,011	6,136	6,263	6,393	6,338	6,469	6,603	6,740	6,880	7,022	7,167	7,316
EBITDA %		*-9%*	*-12%*	*-1%*	*-5%*	*2%*	*0%*	*18%*	*52%*	*54%*	*54%*	*54%*	*54%*	*58%*	*58%*	*58%*	*58%*	*58%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*	*56%*
Depreciation & Amortisation	-	216	216	659	659	1,355	1,355	1,819	1,819	1,924	1,925	1,926	1,928	1,929	1,932	1,934	1,936	1,939	1,941	1,943	1,946	1,949	1,951	1,954	1,957	1,959
EBIT	-	(394)	(465)	(685)	(794)	(1,270)	(1,342)	(412)	2,337	3,136	3,241	3,348	3,456	3,959	4,079	4,202	4,327	4,455	4,397	4,526	4,658	4,792	4,929	5,068	5,211	5,356
Interest cost	-	154	154	467	455	933	904	1,196	1,151	1,173	1,119	1,064	1,010	955	900	845	790	735	680	625	571	516	461	406	351	296
EBT	-	(548)	(619)	(1,152)	(1,249)	(2,203)	(2,246)	(1,607)	1,187	1,963	2,121	2,283	2,447	3,004	3,179	3,357	3,537	3,719	3,717	3,900	4,087	4,276	4,468	4,662	4,860	5,060
Net profit	-	(548)	(619)	(1,152)	(1,249)	(2,203)	(2,246)	(1,607)	1,187	1,963	2,121	2,283	2,447	3,004	3,179	3,357	3,537	3,719	3,717	3,900	4,087	4,276	4,468	4,662	4,860	5,060
Net profit %	*0%*	*-28%*	*-31%*	*-44%*	*-47%*	*-49%*	*-49%*	*-21%*	*15%*	*21%*	*22%*	*23%*	*24%*	*29%*	*30%*	*32%*	*33%*	*34%*	*33%*	*34%*	*35%*	*36%*	*37%*	*37%*	*38%*	*39%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	-	(548)	(619)	(1,152)	(1,249)	(2,203)	(2,246)	(1,607)	1,187	1,963	2,121	2,283	2,447	3,004	3,179	3,357	3,537	3,719	3,717	3,900	4,087	4,276	4,468	4,662	4,860	5,060
Cash profit	-	(332)	(403)	(493)	(590)	(848)	(891)	211	3,006	3,887	4,046	4,209	4,374	4,933	5,111	5,291	5,473	5,658	5,657	5,844	6,033	6,225	6,419	6,616	6,816	7,019

Model run for

Capacity charge (CAD/kW/month) = 23.09, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.9%   Equity IRR for this option: 8.8%

FVB Energy Inc: 7.0 MW Combustor without ORC

Exhibit: Income Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenue													
Capacity Charge	-	1,199	1,223	1,587	1,618	2,758	2,813	4,137	4,219	5,034	5,134	5,237	5,342
Consumption Charge	-	819	835	1,084	1,105	1,884	1,921	2,825	2,882	3,438	3,507	3,577	3,648
Connection Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total revenue	-	2,018	2,058	2,670	2,724	4,641	4,734	6,962	7,101	8,472	8,641	8,814	8,990
Operating Cost													
Variable costs	-	1,923	1,961	2,016	2,057	3,570	3,642	5,355	2,488	2,969	3,028	3,088	3,150
Fixed costs	-	226	298	605	726	830	889	939	972	1,001	1,016	1,032	1,048
Total operating cost	-	2,149	2,259	2,621	2,783	4,400	4,530	6,294	3,460	3,969	4,044	4,121	4,199
EBITDA	-	(131)	(201)	49	(59)	241	204	668	3,641	4,503	4,597	4,693	4,792
EBITDA %		*-7%*	*-10%*	*2%*	*-2%*	*5%*	*4%*	*10%*	*51%*	*53%*	*53%*	*53%*	*53%*
Depreciation & Amortisation	-	216	216	659	659	1,355	1,355	1,631	1,631	1,736	1,737	1,738	1,739
EBIT	-	(348)	(417)	(609)	(718)	(1,114)	(1,151)	(963)	2,010	2,767	2,860	2,956	3,052
Interest cost	-	154	154	467	455	933	904	1,062	1,019	1,046	998	949	899
EBT	-	(502)	(572)	(1,077)	(1,172)	(2,047)	(2,056)	(2,025)	991	1,721	1,862	2,007	2,153
Net profit	-	(502)	(572)	(1,077)	(1,172)	(2,047)	(2,056)	(2,025)	991	1,721	1,862	2,007	2,153
Net profit %	*0%*	*-25%*	*-28%*	*-40%*	*-43%*	*-44%*	*-43%*	*-29%*	*14%*	*20%*	*22%*	*23%*	*24%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	-	(502)	(572)	(1,077)	(1,172)	(2,047)	(2,056)	(2,025)	991	1,721	1,862	2,007	2,153
Cash profit	-	(286)	(355)	(418)	(513)	(692)	(700)	(394)	2,622	3,456	3,599	3,744	3,892

(CAD in 000's)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Revenue													
Capacity Charge	5,449	5,558	5,669	5,782	5,898	6,016	6,136	6,259	6,384	6,512	6,642	6,775	6,910
Consumption Charge	3,721	3,796	3,872	3,949	4,028	4,109	4,191	4,275	4,360	4,447	4,536	4,627	4,720
Connection Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total revenue	9,170	9,353	9,541	9,731	9,926	10,124	10,327	10,534	10,744	10,959	11,178	11,402	11,630
Operating Cost													
Variable costs	2,609	2,661	2,715	2,769	2,824	2,843	2,900	2,958	3,017	3,078	3,139	3,202	3,266
Fixed costs	1,065	1,082	1,100	1,117	1,135	1,154	1,173	1,192	1,211	1,231	1,252	1,272	1,294
Total operating cost	3,674	3,744	3,814	3,886	3,960	3,997	4,073	4,150	4,229	4,309	4,391	4,474	4,560
EBITDA	5,496	5,610	5,726	5,845	5,966	6,128	6,254	6,384	6,516	6,650	6,787	6,927	7,070
EBITDA %	*60%*	*60%*	*60%*	*60%*	*60%*	*61%*	*61%*	*61%*	*61%*	*61%*	*61%*	*61%*	*61%*
Depreciation & Amortisation	1,741	1,743	1,746	1,748	1,750	1,753	1,755	1,758	1,760	1,763	1,766	1,768	1,771
EBIT	3,754	3,867	3,981	4,097	4,216	4,375	4,499	4,626	4,755	4,887	5,022	5,159	5,299
Interest cost	850	800	751	701	652	602	553	503	454	404	355	305	256
EBT	2,905	3,066	3,230	3,396	3,564	3,772	3,946	4,123	4,301	4,483	4,667	4,854	5,043
Net profit	2,905	3,066	3,230	3,396	3,564	3,772	3,946	4,123	4,301	4,483	4,667	4,854	5,043
Net profit %	*32%*	*33%*	*34%*	*35%*	*36%*	*37%*	*38%*	*39%*	*40%*	*41%*	*42%*	*43%*	*43%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	2,905	3,066	3,230	3,396	3,564	3,772	3,946	4,123	4,301	4,483	4,667	4,854	5,043
Cash profit	4,646	4,809	4,975	5,144	5,314	5,525	5,701	5,880	6,062	6,246	6,433	6,622	6,814

Model run for

Capacity charge (CAD/kW/month) = 24.01, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 7.0%   Equity IRR for this option: 8.8%

FVB Energy Inc: Two - 3.05 MWth LNG Cogen Engines

Exhibit: Income Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenue													
Capacity Charge	-	937	956	1,241	1,265	2,156	2,199	3,234	3,299	3,936	4,014	4,095	4,176
Consumption Charge	-	819	835	1,084	1,105	1,884	1,921	2,825	2,882	3,438	3,507	3,577	3,648
Electric Sales	-	-	-	5,047	5,148	5,251	5,356	5,463	5,572	5,684	5,797	5,913	6,032
Total revenue	-	1,756	1,791	7,371	7,519	9,291	9,476	11,523	11,753	13,057	13,318	13,585	13,856
Operating Cost													
Variable costs	-	1,911	1,949	5,165	5,269	6,192	6,316	7,396	6,680	7,516	7,667	7,820	7,976
Fixed costs	-	247	492	839	975	1,040	1,148	1,202	1,255	1,288	1,310	1,332	1,355
Total operating cost	-	2,158	2,441	6,004	6,244	7,232	7,464	8,598	7,935	8,805	8,977	9,152	9,331
EBITDA	-	(402)	(649)	1,367	1,275	2,059	2,012	2,925	3,818	4,252	4,342	4,433	4,526
EBITDA %		*-23%*	*-36%*	*19%*	*17%*	*22%*	*21%*	*25%*	*32%*	*33%*	*33%*	*33%*	*33%*
Depreciation & Amortisation	-	216	216	1,071	1,071	1,488	1,489	1,787	1,788	1,892	1,893	1,894	1,896
EBIT	-	(618)	(866)	296	204	570	524	1,137	2,030	2,360	2,449	2,538	2,630
Interest cost	-	154	154	761	743	1,010	974	1,144	1,097	1,120	1,068	1,014	960
EBT	-	(773)	(1,020)	(465)	(539)	(440)	(450)	(7)	932	1,240	1,381	1,524	1,670
Net profit	-	(773)	(1,020)	(465)	(539)	(440)	(450)	(7)	932	1,240	1,381	1,524	1,670
Net profit %	*0%*	*-44%*	*-57%*	*-6%*	*-7%*	*-5%*	*-5%*	*0%*	*8%*	*9%*	*10%*	*11%*	*12%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	-	(773)	(1,020)	(465)	(539)	(440)	(450)	(7)	932	1,240	1,381	1,524	1,670
Cash profit	-	(556)	(804)	606	532	1,048	1,038	1,780	2,720	3,132	3,274	3,419	3,566

(CAD in 000's)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Revenue													
Capacity Charge	4,260	4,345	4,432	4,521	4,611	4,703	4,797	4,893	4,991	5,091	5,193	5,297	5,403
Consumption Charge	3,721	3,796	3,872	3,949	4,028	4,109	4,191	4,275	4,360	4,447	4,536	4,627	4,720
Electric Sales	6,152	6,275	6,401	6,529	6,659	6,793	6,928	7,067	7,208	7,352	7,500	7,650	7,803
Total revenue	14,134	14,416	14,705	14,999	15,299	15,605	15,917	16,235	16,560	16,891	17,229	17,573	17,925
Operating Cost													
Variable costs	7,822	7,978	8,138	8,301	8,467	8,320	8,486	8,656	8,829	9,005	9,186	9,369	9,557
Fixed costs	1,377	1,401	1,425	1,449	1,474	1,499	1,525	1,552	1,579	1,606	1,634	1,663	1,692
Total operating cost	9,199	9,379	9,563	9,750	9,941	9,819	10,011	10,208	10,408	10,612	10,820	11,032	11,249
EBITDA	4,934	5,037	5,142	5,249	5,358	5,786	5,905	6,028	6,152	6,279	6,409	6,541	6,676
EBITDA %	*35%*	*35%*	*35%*	*35%*	*35%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*	*37%*
Depreciation & Amortisation	1,898	1,900	1,902	1,905	1,907	1,909	1,912	1,914	1,917	1,920	1,922	1,925	1,928
EBIT	3,036	3,137	3,240	3,344	3,451	3,876	3,993	4,113	4,235	4,360	4,487	4,616	4,748
Interest cost	906	852	798	744	690	636	582	528	474	420	366	312	258
EBT	2,130	2,285	2,442	2,600	2,761	3,240	3,411	3,585	3,761	3,939	4,120	4,304	4,490
Net profit	2,130	2,285	2,442	2,600	2,761	3,240	3,411	3,585	3,761	3,939	4,120	4,304	4,490
Net profit %	*15%*	*16%*	*17%*	*17%*	*18%*	*21%*	*21%*	*22%*	*23%*	*23%*	*24%*	*24%*	*25%*
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Retained earnings	2,130	2,285	2,442	2,600	2,761	3,240	3,411	3,585	3,761	3,939	4,120	4,304	4,490
Cash profit	4,028	4,185	4,344	4,505	4,668	5,149	5,323	5,499	5,678	5,859	6,043	6,229	6,418

Model run for

Capacity charge (CAD/kW/month) = 18.77, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.8%   Equity IRR for this option: 8.8%

G.2 Balance Sheets

FVB Energy Inc: Two 3.5 MW Combustor with ORC

Exhibit: Balance Sheet

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Assets																										
Fixed Assets																										
Gross Fixed Assets	-	5,409	5,409	26,326	26,326	36,874	36,888	48,475	48,493	51,102	51,133	51,165	51,212	51,259	51,316	51,374	51,433	51,493	51,555	51,617	51,681	51,746	51,813	51,881	51,950	52,020
Depreciation	-	216	433	1,486	2,539	4,014	5,489	7,428	9,367	11,411	13,456	15,502	17,549	19,598	21,650	23,704	25,760	27,818	29,879	31,943	34,009	36,077	38,149	40,222	42,299	44,378
Net Fixed Assets	-	5,193	4,976	24,840	23,787	32,860	31,399	41,048	39,126	39,692	37,678	35,664	33,663	31,661	29,666	27,670	25,673	23,675	21,675	19,674	17,672	15,669	13,664	11,658	9,651	7,642
Capital Work-in-Progress	5,409	-	20,917	-	10,548	-	11,574	-	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed Assets	5,409	5,193	25,893	24,840	34,335	32,860	42,973	41,048	41,717	39,692	37,678	35,664	33,663	31,661	29,666	27,670	25,673	23,675	21,675	19,674	17,672	15,669	13,664	11,658	9,651	7,642
Current Assets																										
Receivables	-	452	461	598	610	1,039	1,060	1,558	1,590	1,896	1,934	1,973	2,013	2,053	2,094	2,136	2,178	2,222	2,266	2,312	2,358	2,405	2,453	2,502	2,552	2,603
Operating cash balance	-	90	97	65	69	96	101	101	91	105	107	109	111	120	123	125	127	129	142	144	147	150	153	155	158	161
Other current assets																										
Total Current Assets	-	*541*	*557*	*662*	*678*	*1,135*	*1,161*	*1,660*	*1,681*	*2,001*	*2,041*	*2,082*	*2,123*	*2,173*	*2,216*	*2,261*	*2,306*	*2,351*	*2,408*	*2,456*	*2,505*	*2,555*	*2,606*	*2,658*	*2,711*	*2,765*
Surplus Cash	-	-	-	-	-	-	-	1,156	2,892	5,265	7,984	10,869	13,907	16,934	20,112	23,461	26,982	30,677	34,322	38,131	42,116	46,282	50,628	55,159	59,877	64,784
Total Assets	5,409	5,734	26,451	25,503	35,014	33,996	44,134	43,863	46,291	46,958	47,703	48,614	49,693	50,768	51,995	53,392	54,960	56,704	58,405	60,261	62,294	64,505	66,898	69,475	72,238	75,190
Liabilities																										
Equity																										
Paid-up Capital	2,164	3,023	12,023	12,231	17,028	17,221	21,924	21,924	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960	22,960
Retained Earnings	-	(713)	(1,561)	(2,523)	(3,514)	(4,149)	(4,783)	(4,168)	(3,150)	(1,346)	620	2,753	5,052	7,332	9,780	12,397	15,186	18,150	21,051	24,127	27,379	30,810	34,423	38,219	42,201	46,372
Total Equity	2,164	2,309	10,462	9,708	13,514	13,072	17,141	17,756	19,810	21,614	23,581	25,713	28,012	30,292	32,740	35,357	38,146	41,110	44,011	47,087	50,339	53,771	57,383	61,179	65,161	69,332
Debt																										
Term Loan	3,245	3,245	15,666	15,034	20,731	19,846	25,905	24,743	25,134	23,910	22,685	21,460	20,235	19,010	17,785	16,560	15,335	14,110	12,885	11,660	10,435	9,210	7,985	6,760	5,536	5,536
Total Debt	3,245	3,245	15,666	15,034	20,731	19,846	25,905	24,743	25,134	23,910	22,685	21,460	20,235	19,010	17,785	16,560	15,335	14,110	12,885	11,660	10,435	9,210	7,985	6,760	5,536	5,536
Current Liabilities																										
Payables	-	179	193	129	137	193	203	202	183	210	213	217	221	241	245	250	254	259	284	289	294	300	305	311	317	323
Connection Charge - current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current portion of LT debt	-	-	130	632	632	885	885	1,163	1,163	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	-
Total Current Liabilities	-	179	323	761	769	1,078	1,088	1,365	1,346	1,434	1,438	1,442	1,446	1,466	1,470	1,475	1,479	1,484	1,508	1,514	1,519	1,525	1,530	1,536	1,542	323
Connection Charge - non current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	5,409	5,734	26,451	25,503	35,014	33,996	44,134	43,863	46,291	46,958	47,703	48,614	49,693	50,768	51,995	53,392	54,960	56,704	58,405	60,261	62,294	64,505	66,898	69,475	72,238	75,190
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

Model run for

Capacity charge (CAD/kW/month) = 19.78, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.7%   Equity IRR for this option: 8.8%

FVB Energy Inc: 7.0 MW Combustor with ORC

Exhibit: Balance Sheet

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Assets																										
Fixed Assets																										
Gross Fixed Assets	-	5,409	5,409	16,471	16,471	33,874	33,888	45,475	45,493	48,102	48,133	48,165	48,212	48,259	48,316	48,374	48,433	48,493	48,555	48,617	48,681	48,746	48,813	48,881	48,950	49,020
Depreciation	-	216	433	1,092	1,750	3,105	4,461	6,279	8,099	10,022	11,947	13,873	15,801	17,730	19,662	21,595	23,532	25,470	27,411	29,354	31,300	33,249	35,200	37,154	39,111	41,070
Net Fixed Assets	-	5,193	4,976	15,379	14,721	30,769	29,427	39,196	37,394	38,080	36,186	34,292	32,411	30,529	28,654	26,779	24,901	23,023	21,144	19,263	17,381	15,497	13,613	11,727	9,839	7,950
Capital Work-in-Progress	5,409	-	11,062	-	17,403	-	11,574	-	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed Assets	5,409	5,193	16,038	15,379	32,124	30,769	41,001	39,196	39,985	38,080	36,186	34,292	32,411	30,529	28,654	26,779	24,901	23,023	21,144	19,263	17,381	15,497	13,613	11,727	9,839	7,950
Current Assets																										
Receivables	-	493	503	652	665	1,134	1,157	1,701	1,735	2,070	2,111	2,153	2,196	2,240	2,285	2,331	2,378	2,425	2,474	2,523	2,574	2,625	2,677	2,731	2,786	2,841
Operating cash balance	-	90	94	110	117	185	192	225	116	134	137	139	142	128	130	133	135	138	148	151	154	157	160	163	166	169
Other current assets																										
Total Current Assets	*-*	*583*	*597*	*762*	*782*	*1,319*	*1,349*	*1,926*	*1,851*	*2,204*	*2,248*	*2,293*	*2,338*	*2,368*	*2,416*	*2,464*	*2,513*	*2,563*	*2,622*	*2,674*	*2,727*	*2,782*	*2,837*	*2,894*	*2,951*	*3,010*
Surplus Cash	-	-	-	-	-	-	-	-	1,755	4,216	7,039	10,024	13,158	16,833	20,692	24,729	28,946	33,345	37,750	42,332	47,100	52,058	57,208	62,553	68,096	73,839
Total Assets	5,409	5,775	16,635	16,142	32,906	32,088	42,350	41,122	43,591	44,500	45,473	46,608	47,907	49,731	51,762	53,971	56,360	58,931	61,516	64,269	67,208	70,337	73,658	77,174	80,886	84,800
Liabilities																										
Equity																										
Paid-up Capital	2,164	2,899	7,732	8,489	16,442	18,084	24,447	25,574	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611	26,611
Retained Earnings	-	(548)	(1,167)	(2,319)	(3,568)	(5,771)	(8,017)	(9,625)	(8,438)	(6,475)	(4,354)	(2,070)	376	3,380	6,560	9,917	13,454	17,173	20,890	24,790	28,877	33,153	37,621	42,283	47,143	52,203
Total Equity	2,164	2,351	6,564	6,169	12,873	12,313	16,430	15,950	18,173	20,136	22,257	24,540	26,987	29,991	33,171	36,528	40,064	43,784	47,500	51,401	55,488	59,764	64,232	68,894	73,754	78,814
Debt																										
Term Loan	3,245	3,245	9,753	9,357	19,404	18,591	24,722	23,632	24,096	22,943	21,790	20,637	19,484	18,331	17,178	16,025	14,872	13,719	12,566	11,413	10,260	9,107	7,954	6,801	5,649	5,649
Total Debt	3,245	3,245	9,753	9,357	19,404	18,591	24,722	23,632	24,096	22,943	21,790	20,637	19,484	18,331	17,178	16,025	14,872	13,719	12,566	11,413	10,260	9,107	7,954	6,801	5,649	5,649
Current Liabilities																										
Payables	-	179	188	220	233	371	384	450	232	268	273	278	283	256	261	266	271	276	296	302	308	313	319	325	331	337
Connection Charge - current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current portion of LT debt	-	-	130	395	395	813	813	1,091	1,091	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	-
Total Current Liabilities	-	179	318	615	628	1,184	1,197	1,540	1,323	1,421	1,426	1,431	1,436	1,409	1,414	1,419	1,424	1,429	1,449	1,455	1,460	1,466	1,472	1,478	1,484	337
Connection Charge - non current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	5,409	5,775	16,635	16,142	32,906	32,088	42,350	41,122	43,591	44,500	45,473	46,608	47,907	49,731	51,762	53,971	56,360	58,931	61,516	64,269	67,208	70,337	73,658	77,174	80,886	84,800
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

Model run for

Capacity charge (CAD/kW/month) = 23.09, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.9%   Equity IRR for this option: 8.8%

Confidential

FVB Energy Inc: 7.0 MW Combustor without ORC

Exhibit: Balance Sheet

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Assets																										
Fixed Assets																										
Gross Fixed Assets	-	5,409	5,409	16,471	16,471	33,874	33,888	40,770	40,788	43,397	43,428	43,460	43,507	43,554	43,611	43,669	43,728	43,788	43,850	43,912	43,976	44,041	44,108	44,176	44,245	44,315
Depreciation	-	216	433	1,092	1,750	3,105	4,461	6,091	7,722	9,458	11,194	12,932	14,671	16,413	18,156	19,902	21,650	23,400	25,153	26,908	28,666	30,426	32,189	33,955	35,723	37,494
Net Fixed Assets	-	5,193	4,976	15,379	14,721	30,769	29,427	34,679	33,066	33,940	32,234	30,528	28,835	27,142	25,455	23,767	22,078	20,388	18,697	17,004	15,311	13,615	11,919	10,221	8,522	6,821
Capital Work-in-Progress	5,409	-	11,062	-	17,403	-	6,869	-	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed Assets	5,409	5,193	16,038	15,379	32,124	30,769	36,296	34,679	35,657	33,940	32,234	30,528	28,835	27,142	25,455	23,767	22,078	20,388	18,697	17,004	15,311	13,615	11,919	10,221	8,522	6,821
Current Assets																										
Receivables	-	504	515	668	681	1,160	1,184	1,740	1,775	2,118	2,160	2,203	2,248	2,293	2,338	2,385	2,433	2,481	2,531	2,582	2,633	2,686	2,740	2,795	2,850	2,907
Operating cash balance	-	90	94	109	116	183	189	262	144	165	169	172	175	153	156	159	162	165	167	170	173	176	180	183	186	190
Other current assets																										
Total Current Assets	*-*	*594*	*609*	*777*	*797*	*1,344*	*1,372*	*2,003*	*1,919*	*2,283*	*2,329*	*2,375*	*2,423*	*2,446*	*2,494*	*2,544*	*2,595*	*2,646*	*2,698*	*2,751*	*2,806*	*2,862*	*2,919*	*2,978*	*3,037*	*3,097*
Surplus Cash	-	-	-	-	-	-	-	-	1,474	3,612	6,101	8,733	11,498	14,989	18,659	22,493	26,493	30,661	35,037	39,588	44,316	49,223	54,312	59,586	65,046	70,696
Total Assets	5,409	5,787	16,647	16,156	32,921	32,112	37,668	36,682	39,050	39,835	40,664	41,637	42,756	44,577	46,609	48,804	51,166	53,696	56,432	59,344	62,433	65,701	69,150	72,784	76,605	80,615
Liabilities																										
Equity																										
Paid-up Capital	2,164	2,864	7,650	8,335	16,212	17,711	22,003	23,707	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744	24,744
Retained Earnings	-	(502)	(1,074)	(2,150)	(3,323)	(5,369)	(7,425)	(9,449)	(8,458)	(6,738)	(4,876)	(2,869)	(716)	2,188	5,255	8,484	11,880	15,444	19,217	23,163	27,285	31,587	36,070	40,736	45,590	50,633
Total Equity	2,164	2,362	6,576	6,185	12,889	12,342	14,578	14,258	16,285	18,006	19,868	21,875	24,028	26,932	29,998	33,228	36,624	40,188	43,960	47,907	52,029	56,330	60,813	65,480	70,334	75,377
Debt																										
Term Loan	3,245	3,245	9,753	9,357	19,404	18,591	21,899	20,922	21,498	20,458	19,418	18,378	17,338	16,298	15,258	14,218	13,178	12,138	11,098	10,058	9,018	7,978	6,938	5,898	4,858	4,858
Total Debt	3,245	3,245	9,753	9,357	19,404	18,591	21,899	20,922	21,498	20,458	19,418	18,378	17,338	16,298	15,258	14,218	13,178	12,138	11,098	10,058	9,018	7,978	6,938	5,898	4,858	4,858
Current Liabilities																										
Payables	-	179	188	218	232	367	378	525	288	331	337	343	350	306	312	318	324	330	333	339	346	352	359	366	373	380
Connection Charge - current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current portion of LT debt	-	-	130	395	395	813	813	978	978	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	-
Total Current Liabilities	-	179	318	614	627	1,180	1,191	1,502	1,266	1,371	1,377	1,383	1,390	1,346	1,352	1,358	1,364	1,370	1,373	1,379	1,386	1,392	1,399	1,406	1,413	380
Connection Charge - non current portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	5,409	5,787	16,647	16,156	32,921	32,112	37,668	36,682	39,050	39,835	40,664	41,637	42,756	44,577	46,609	48,804	51,166	53,696	56,432	59,344	62,433	65,701	69,150	72,784	76,605	80,615
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

Model run for

Capacity charge (CAD/kW/month) = 24.01, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 7.0%   Equity IRR for this option: 8.8%

FVB Energy Inc: Two - 3.05 MWth LNG Cogen Engines

Exhibit: Balance Sheet

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Assets													
Fixed Assets													
Gross Fixed Assets	-	5,409	5,409	26,775	26,775	37,211	37,225	44,686	44,704	47,313	47,344	47,376	47,423
Depreciation	-	216	433	1,504	2,575	4,063	5,552	7,339	9,127	11,019	12,912	14,807	16,703
Net Fixed Assets	-	5,193	4,976	25,271	24,200	33,148	31,673	37,347	35,577	36,294	34,432	32,570	30,720
Capital Work-in-Progress	5,409	-	21,366	-	10,436	-	7,448	-	2,591	-	-	-	-
Total Fixed Assets	5,409	5,193	26,342	25,271	34,636	33,148	39,121	37,347	38,168	36,294	34,432	32,570	30,720
Current Assets													
Receivables	-	439	448	581	593	1,010	1,030	1,515	1,545	1,843	1,880	1,918	1,956
Operating cash balance	-	90	102	40	46	83	88	131	98	130	132	135	137
Other current assets													
Total Current Assets	-	*529*	*550*	*621*	*638*	*1,092*	*1,118*	*1,646*	*1,644*	*1,973*	*2,013*	*2,053*	*2,094*
Surplus Cash	-	-	-	281	164	189	306	738	2,306	4,081	6,156	8,374	10,723
Total Assets	5,409	5,722	26,892	26,173	35,439	34,430	40,545	39,731	42,118	42,349	42,601	42,996	43,537
Liabilities													
Equity													
Paid-up Capital	2,164	3,069	12,416	12,416	16,591	16,591	19,570	19,570	20,606	20,606	20,606	20,606	20,606
Retained Earnings	-	(773)	(1,793)	(2,258)	(2,797)	(3,238)	(3,688)	(3,695)	(2,762)	(1,522)	(142)	1,383	3,052
Total Equity	2,164	2,296	10,623	10,158	13,793	13,353	15,882	15,875	17,844	19,084	20,465	21,989	23,659
Debt													
Term Loan	3,245	3,245	15,935	15,293	20,912	20,019	23,594	22,522	23,005	21,871	20,737	19,603	18,469
Total Debt	3,245	3,245	15,935	15,293	20,912	20,019	23,594	22,522	23,005	21,871	20,737	19,603	18,469
Current Liabilities													
Payables	-	180	203	80	91	165	176	261	197	260	265	270	275
Connection Charge - current portion	-	-	-	-	-	-	-	-	-	-	-	-	-
Current portion of LT debt	-	-	130	643	643	893	893	1,072	1,072	1,134	1,134	1,134	1,134
Total Current Liabilities	-	180	333	722	734	1,058	1,069	1,333	1,269	1,394	1,399	1,404	1,409
Connection Charge - non current portion	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	5,409	5,722	26,892	26,173	35,439	34,430	40,545	39,731	42,118	42,349	42,601	42,996	43,537
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

(CAD in 000's)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Assets													
Fixed Assets													
Gross Fixed Assets	47,470	47,527	47,585	47,644	47,704	47,766	47,828	47,892	47,957	48,024	48,092	48,161	48,231
Depreciation	18,600	20,500	22,403	24,307	26,214	28,124	30,035	31,950	33,867	35,786	37,709	39,634	41,562
Net Fixed Assets	28,870	27,027	25,182	23,337	21,490	19,642	17,793	15,942	14,090	12,237	10,383	8,527	6,670
Capital Work-in-Progress	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed Assets	28,870	27,027	25,182	23,337	21,490	19,642	17,793	15,942	14,090	12,237	10,383	8,527	6,670
Current Assets													
Receivables	1,995	2,035	2,076	2,117	2,160	2,203	2,247	2,292	2,338	2,385	2,432	2,481	2,531
Operating cash balance	127	129	132	134	137	126	128	131	133	136	138	141	144
Other current assets													
Total Current Assets	*2,122*	*2,165*	*2,208*	*2,252*	*2,297*	*2,329*	*2,376*	*2,423*	*2,471*	*2,520*	*2,571*	*2,622*	*2,674*
Surplus Cash	13,520	16,477	19,590	22,863	26,297	30,197	34,282	38,541	42,976	47,591	52,386	57,366	62,533
Total Assets	44,512	45,668	46,980	48,451	50,083	52,168	54,450	56,906	59,538	62,348	65,340	68,515	71,876
Liabilities													
Equity													
Paid-up Capital	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606	20,606
Retained Earnings	5,183	7,468	9,909	12,510	15,270	18,510	21,922	25,507	29,268	33,207	37,328	41,632	46,122
Total Equity	25,789	28,074	30,516	33,116	35,877	39,117	42,528	46,113	49,874	53,813	57,934	62,238	66,728
Debt													
Term Loan	17,335	16,201	15,067	13,933	12,799	11,665	10,531	9,397	8,263	7,129	5,995	4,861	4,861
Total Debt	17,335	16,201	15,067	13,933	12,799	11,665	10,531	9,397	8,263	7,129	5,995	4,861	4,861
Current Liabilities													
Payables	254	259	264	268	273	252	257	262	267	272	277	282	287
Connection Charge - current portion	-	-	-	-	-	-	-	-	-	-	-	-	-
Current portion of LT debt	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	-
Total Current Liabilities	1,388	1,393	1,398	1,402	1,407	1,386	1,391	1,396	1,401	1,406	1,411	1,416	287
Connection Charge - non current portion	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities	44,512	45,668	46,980	48,451	50,083	52,168	54,450	56,906	59,538	62,348	65,340	68,515	71,876
Check	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK	OK

Model run for

Capacity charge (CAD/kW/month) = 18.77, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.8%   Equity IRR for this option: 8.8%

G.3 Cash Flow Statements

FVB Energy Inc: Two 3.5 MW Combustor with ORC

Exhibit: Cash Flow Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inflows													
Cash profit	-	(497)	(632)	91	62	841	841	2,554	2,957	3,848	4,011	4,178	4,347
Equity drawdown	2,164	859	9,000	208	4,797	193	4,703	-	1,036	-	-	-	-
Debt drawdown	3,245	-	12,550	-	6,329	-	6,944	-	1,555	-	-	-	-
Total inflows	5,409	362	20,919	299	11,188	1,033	12,488	2,554	5,548	3,848	4,011	4,178	4,347
Outflows													
Capital Expenditure	5,409	-	20,917	-	10,548	-	11,588	14	2,609	18	31	32	47
Increase/(decrease) in working capital	-	362	2	169	8	401	16	499	41	294	36	37	38
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	-	-	-	130	632	632	885	885	1,163	1,163	1,225	1,225	1,225
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	5,409	362	20,919	299	11,188	1,033	12,488	1,398	3,812	1,475	1,292	1,293	1,309
Surplus/(deficit)	-	-	-	-	-	-	-	1,156	1,736	2,373	2,719	2,885	3,038
Opening cash balance	-	-	-	-	-	-	-	-	*1,156*	*2,892*	*5,265*	*7,984*	*10,869*
Closing cash balance	-	-	-	-	-	-	-	*1,156*	*2,892*	*5,265*	*7,984*	*10,869*	*13,907*

(CAD in 000's)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Inflows													
Cash profit	4,329	4,499	4,671	4,845	5,022	4,963	5,139	5,318	5,500	5,684	5,870	6,059	6,250
Equity drawdown	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt drawdown	-	-	-	-	-	-	-	-	-	-	-	-	-
Total inflows	4,329	4,499	4,671	4,845	5,022	4,963	5,139	5,318	5,500	5,684	5,870	6,059	6,250
Outflows													
Capital Expenditure	48	57	58	59	60	61	63	64	65	66	68	69	71
Increase/(decrease) in working capital	30	39	40	40	41	32	43	44	44	45	46	47	48
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225	1,225
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	1,303	1,321	1,322	1,324	1,326	1,318	1,330	1,332	1,335	1,337	1,339	1,341	1,344
Surplus/(deficit)	3,026	3,179	3,349	3,521	3,696	3,644	3,809	3,986	4,165	4,347	4,531	4,718	4,907
Opening cash balance	*13,907*	*16,934*	*20,112*	*23,461*	*26,982*	*30,677*	*34,322*	*38,131*	*42,116*	*46,282*	*50,628*	*55,159*	*59,877*
Closing cash balance	*16,934*	*20,112*	*23,461*	*26,982*	*30,677*	*34,322*	*38,131*	*42,116*	*46,282*	*50,628*	*55,159*	*59,877*	*64,784*

Model run for
  Capacity charge (CAD/kW/month) = 19.78, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000
  Contracted minimum EFLH = 0,000, Actual EFLH = 2,811
Project IRR for this option: 6.7%   Equity IRR for this option: 8.8%

FVB Energy Inc: 7.0 MW Combustor with ORC

Exhibit: Cash Flow Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inflows													
Cash profit	-	(332)	(403)	(493)	(590)	(848)	(891)	211	3,006	3,887	4,046	4,209	4,374
Equity drawdown	2,164	735	4,833	757	7,953	1,643	6,363	1,127	1,036	-	-	-	-
Debt drawdown	3,245	-	6,637	-	10,442	-	6,944	-	1,555	-	-	-	-
Total inflows	5,409	403	11,067	264	17,805	795	12,416	1,338	5,597	3,887	4,046	4,209	4,374
Outflows													
Capital Expenditure	5,409	-	11,062	-	17,403	-	11,588	14	2,609	18	31	32	47
Increase/(decrease) in working capital	-	403	5	134	6	400	16	512	143	317	39	40	40
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	-	-	-	130	395	395	813	813	1,091	1,091	1,153	1,153	1,153
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	5,409	403	11,067	264	17,805	795	12,416	1,338	3,843	1,426	1,223	1,224	1,240
Surplus/(deficit)	-	-	-	-	-	-	-	-	1,755	2,461	2,823	2,985	3,134
Opening cash balance	-	-	-	-	-	-	-	-	-	*1,755*	*4,216*	*7,039*	*10,024*
Closing cash balance	-	-	-	-	-	-	-	-	*1,755*	*4,216*	*7,039*	*10,024*	*13,158*

(CAD in 000's)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Inflows													
Cash profit	4,933	5,111	5,291	5,473	5,658	5,657	5,844	6,033	6,225	6,419	6,616	6,816	7,019
Equity drawdown	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt drawdown	-	-	-	-	-	-	-	-	-	-	-	-	-
Total inflows	4,933	5,111	5,291	5,473	5,658	5,657	5,844	6,033	6,225	6,419	6,616	6,816	7,019
Outflows													
Capital Expenditure	48	57	58	59	60	61	63	64	65	66	68	69	71
Increase/(decrease) in working capital	58	42	43	44	45	38	47	48	49	50	51	52	53
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	1,258	1,252	1,254	1,256	1,258	1,252	1,262	1,264	1,267	1,269	1,271	1,274	1,276
Surplus/(deficit)	3,675	3,859	4,037	4,217	4,400	4,405	4,582	4,768	4,958	5,150	5,345	5,543	5,743
Opening cash balance	*13,158*	*16,833*	*20,692*	*24,729*	*28,946*	*33,345*	*37,750*	*42,332*	*47,100*	*52,058*	*57,208*	*62,553*	*68,096*
Closing cash balance	*16,833*	*20,692*	*24,729*	*28,946*	*33,345*	*37,750*	*42,332*	*47,100*	*52,058*	*57,208*	*62,553*	*68,096*	*73,839*

Model run for

Capacity charge (CAD/kW/month) = 23.09, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.9%   Equity IRR for this option: 8.8%

FVB Energy Inc: 7.0 MW Combustor without ORC

Exhibit: Cash Flow Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Inflows																										
Cash profit	-	(286)	(355)	(418)	(513)	(692)	(700)	(394)	2,622	3,456	3,599	3,744	3,892	4,646	4,809	4,975	5,144	5,314	5,525	5,701	5,880	6,062	6,246	6,433	6,622	6,814
Equity drawdown	2,164	701	4,786	686	7,877	1,499	4,292	1,704	1,036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt drawdown	3,245	-	6,637	-	10,442	-	4,121	-	1,555	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total inflows	5,409	415	11,067	268	17,805	807	7,713	1,310	5,213	3,456	3,599	3,744	3,892	4,646	4,809	4,975	5,144	5,314	5,525	5,701	5,880	6,062	6,246	6,433	6,622	6,814
Outflows																										
Capital Expenditure	5,409	-	11,062	-	17,403	-	6,883	14	2,609	18	31	32	47	48	57	58	59	60	61	63	64	65	66	68	69	71
Increase/(decrease) in working capital	-	415	5	138	7	412	18	483	153	321	39	40	41	67	43	44	45	46	48	47	48	49	50	51	52	53
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	-	-	-	130	395	395	813	813	978	978	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	5,409	415	11,067	268	17,805	807	7,713	1,310	3,740	1,317	1,110	1,112	1,127	1,154	1,140	1,142	1,144	1,146	1,150	1,150	1,152	1,155	1,157	1,159	1,162	1,164
Surplus/(deficit)	-	-	-	-	-	-	-	-	1,474	2,139	2,488	2,633	2,765	3,491	3,670	3,834	4,000	4,169	4,376	4,551	4,728	4,907	5,089	5,273	5,460	5,650
Opening cash balance	-	-	-	-	-	-	-	-	-	*1,474*	*3,612*	*6,101*	*8,733*	*11,498*	*14,989*	*18,659*	*22,493*	*26,493*	*30,661*	*35,037*	*39,588*	*44,316*	*49,223*	*54,312*	*59,586*	*65,046*
Closing cash balance	-	-	-	-	-	-	-	-	*1,474*	*3,612*	*6,101*	*8,733*	*11,498*	*14,989*	*18,659*	*22,493*	*26,493*	*30,661*	*35,037*	*39,588*	*44,316*	*49,223*	*54,312*	*59,586*	*65,046*	*70,696*

Model run for

Capacity charge (CAD/kW/month) = 24.01, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 7.0% Equity IRR for this option: 8.8%

FVB Energy Inc: Two - 3.05 MWth LNG Cogen Engines

Exhibit: Cash Flow Statement

(CAD in 000's)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Inflows																										
Cash profit	-	(556)	(804)	606	532	1,048	1,038	1,780	2,720	3,132	3,274	3,419	3,566	4,028	4,185	4,344	4,505	4,668	5,149	5,323	5,499	5,678	5,859	6,043	6,229	6,418
Equity drawdown	2,164	905	9,347	-	4,174	-	2,979	-	1,036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt drawdown	3,245	-	12,820	-	6,262	-	4,469	-	1,555	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total inflows	5,409	349	21,363	606	10,968	1,048	8,486	1,780	5,311	3,132	3,274	3,419	3,566	4,028	4,185	4,344	4,505	4,668	5,149	5,323	5,499	5,678	5,859	6,043	6,229	6,418
Outflows																										
Capital Expenditure	5,409	-	21,366	-	10,436	-	7,462	14	2,609	18	31	32	47	48	57	58	59	60	61	63	64	65	66	68	69	71
Increase/(decrease) in working capital	-	349	(3)	195	6	380	15	442	62	267	34	35	36	50	38	38	39	40	54	42	43	43	44	45	46	47
Increase/(decrease) in connection charge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt repayment	-	-	-	130	643	643	893	893	1,072	1,072	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134
Dividend	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total outflows	5,409	349	21,363	325	11,084	1,023	8,369	1,349	3,743	1,357	1,200	1,201	1,216	1,231	1,228	1,230	1,232	1,234	1,249	1,238	1,240	1,243	1,245	1,247	1,249	1,252
Surplus/(deficit)	-	-	-	281	(117)	25	117	432	1,568	1,775	2,074	2,218	2,349	2,797	2,957	3,114	3,273	3,434	3,900	4,085	4,259	4,435	4,614	4,796	4,980	5,166
Opening cash balance	-	-	-	-	*281*	*164*	*189*	*306*	*738*	*2,306*	*4,081*	*6,156*	*8,374*	*10,723*	*13,520*	*16,477*	*19,590*	*22,863*	*26,297*	*30,197*	*34,282*	*38,541*	*42,976*	*47,591*	*52,386*	*57,366*
Closing cash balance	-	-	-	*281*	*164*	*189*	*306*	*738*	*2,306*	*4,081*	*6,156*	*8,374*	*10,723*	*13,520*	*16,477*	*19,590*	*22,863*	*26,297*	*30,197*	*34,282*	*38,541*	*42,976*	*47,591*	*52,386*	*57,366*	*62,533*

Model run for

Capacity charge (CAD/kW/month) = 18.77, Consumption charge (CAD/kWh) = 0.07, Connection fee (CAD/kW) = 000

Contracted minimum EFLH = 0,000, Actual EFLH = 2,811

Project IRR for this option: 6.8%   Equity IRR for this option: 8.8%

Appendix H - Design Basis Document

Whitehorse Community Energy Project

Community Energy System
Design Basis Document

Final Issued: January 18, 2013

CONFIDENTIAL

Submitted to:

YUKON ENERGY CORPORATION
David Morrison
President and Chief Executive Officer
2 Miles Canyon Rd.
Whitehorse, YT Y1A 6S7

Prepared by:

Suite 350, 13220 St Albert Trail NW
Edmonton, AB T5L 4W1

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1 Introduction

FVB Energy Inc. (FVB) has prepared this document for the steering committee comprised of Yukon Energy, City of Whitehorse, Yukon Cold Climate Innovation Centre, Energy Solutions Centre, and the Government of Yukon. The design basis document provides the basis for establishing the detailed design of a system moving forward.

The first section of the Feasibility Study began with estimating the building loads and energy analysis for all customers studied. From there, the zones were identified and compared to determine which scenario would be best suited to develop into CES within Whitehorse. The steering committee selected a customer base that includes the areas along Hospital Road, Lewes Boulevard and the downtown core.

Next, the energy source screening looked at eight alternatives to supply baseload heating to the proposed CES. From these results and under the direction of the Steering Committee, two concepts were selected to develop into technical concepts:

- Biomass combustor with ORC baseload heating and electrical generation
  - Additional fuel oil back-up boilers developed at same energy centre
- LNG cogeneration baseload heating and electrical generation
  - Additional LNG back-up boilers developed at same energy centre

The concept design includes the following:

- A general description of the major equipment and assumptions for each energy centre
- Concept layouts, process single lines, and electrical single lines for each energy centre
- Description of recommended buried piping systems materials, proposed pipe routing, and preliminary pipe sizing
- A general description of the energy transfer stations (ETS's) proposed to interface to the CES with the in-building space heating and domestic hot water systems.
- Flow schematics for the ETS concept for twelve of the proposed 43 buildings.

This document provides a detailed description of the concepts that are further developed in the business plan. These details are summarized in the design plan, and are used to determine the capital cost component and associated operational costs. From these values, the business cases and marketing plans can be developed.

2 Biomass Concept Design Basis

This section outlines the biomass with organic Rankine cycle concept of the new Community Energy System (CES) proposed for the City of Whitehorse, YT. This document will serve as the preliminary technical reference for the “Biomass” system’s design.

While a biomass with an organic Rankine cycle was selected in this concept, there are other competitive technologies that involve wood fuel conversion. Before proceeding to detailed design work, other technology options should be evaluated.

2.1 General System Description

The proposed CES will include three main sub-systems, consisting of thermal heat energy production centre(s), a distribution piping system and individual building connections/metering stations for the various customers on the system. Hot water will be produced at the heating energy centres and distributed through the main distribution piping system, also referred to as the “primary side piping loop”. Space heating and domestic hot water production will typically be performed on the customer side in separate circulating loops, also referred to as the “building secondary loops”. Energy will be transferred from the primary loop to each building, or customer, through heat exchangers, also referred to as Energy Transfer Stations (ETS). These energy transfer points also serve as energy metering points and temperature control points for the building secondary loops.

The design concept of each of the main system elements is described in more detail in the following sections of this document.

2.2 System Loads and Phasing

The potential customer building heating loads that the proposed CES would serve are summarized in the following table. The phasing indicated is based on the anticipated order in which each energy centre would be established. The proposed heating energy centre adjacent to the hospital is expected to be the quickest to establish. This centre uses existing capacity and operation personnel, reducing capital costs in the early stages and while providing system reliability.

With the goal of getting the Community system started and operating as soon as possible, the heating energy centre at the hospital is deemed to be the first heating energy centre constructed with associated distribution pipe network and customer loads served.

Load and energy estimations during each phase are shown below in Table 1. Details of the final version of the load and energy table used for the CES concept can be found in Appendix I . The finalized load encompasses all changes to building connections and the final energy from fuel data results.

Table 1 - Summary of System Heating Loads and Phasing

Description	Contract Load, kW_{th}	Diversified Load, kW_{th}	Thermal Energy, MWh	ETS # of Customers Connected	DPS Trench Meters Installed
Phase 1 (P1)	4.8	4.1	12,580	6	1,770 m
Phase 2 (P1 & P2)	6.1	5.2	16,120	10	4,240 m
Phase 3 (P1 & P2)	10.2	8.7	24,870	22	6,140 m
Phase 4 (P1, P2 & P3)	14.7	12.5	35,450	35	7,740 m
Full Build-out	17.2	14.6	41,100	43	8,700 m

2.3 Energy Production Centres

2.3.1 General

Three thermal energy centres are proposed for this project. The first energy centre, P1, would be established as an addition to the existing hospital boiler energy centre. This energy centre is key to the initial development of Community heating in Whitehorse. P1 would initially serve the immediate area around the hospital, and then transition to a back-up energy centre role as the overall system continues to develop.

The second energy centre, P2, would be established south of the current Yukon Energy facilities to serve as the main energy producing facility for the proposed community system. The P2 energy centre would be operated continuously in a baseload operating role, using the proposed alternative energy concept. In this proposed scenario, the biomass ORC system is assumed to be thermal load following, and all electricity produced is assumed to be sold to the greater grid. The fuel oil boilers at P2 serve as peaking boilers for the system.

The final energy centre, P3, would be installed in the downtown and would serve as a back-up energy centre. Adding the energy centre in the downtown core will delay capital expenditure and significantly improve the reliability of the system. Consideration should be give to using existing floor space and/or boiler capacity from one of the larger government buildings to reduce capital and operating costs.

In time, each of the areas served by their respective energy centres would become interconnected to provide security of energy supply.

Preliminary drawings for each of the proposed energy centres can be found in Appendix I and include the following drawings:

- Energy Centre P1 – Steam Convertor Station Schematic
- Energy Centre P1 – Steam Convertor Station Preliminary Equipment Layout
- Energy Centre P1 - Preliminary Electrical Single Line Diagram

- Energy Centre P2 – Biomass Combustors and ORC Flow Schematic
- Energy Centre P2 – Biomass Heat Recovery Schematic
- Energy Centre P2 – Biomass Concept Preliminary Equipment Layout
- Energy Centre P2 – Biomass Concept Preliminary Electrical Single Line Diagram

- Energy Centre P3 – Fuel Oil Boiler Flow Schematic
- Energy Centre P3 – Downtown Energy Centre Preliminary Equipment Layout
- Energy Centre P3 - Preliminary Electrical Single Line Diagram

2.3.2 Overall Design Parameters

The following tables outline the design data applicable to the Energy Centres.

Table 2 - General Climatic Design Data

Description	Summer	Winter
Outdoor Design Conditions		
Dry Bulb Design Temperature	25 °C (77 °F)	-41 °C (-41.8 °F)
Mean coinciding Wet Bulb Temperature	15 °C (60 °F)	
Indoor Design Conditions		
Energy Centre Boiler Rooms	35 °C (95°F)	15 °C (60°F)
Elevation, meters ASL	640m (2,100 ft) Hospital & Downtown 660m (2,165ft) Energy Centre P2	

Table 3 - Energy Centre Operating Design Criteria

Description	Winter	Summer / Shoulder Months
Energy Centre P1 Hot Water Heating		
Installed Heating Capacity; kW_{th}	4,000 kW_{th}	
Hot Water Supply Temp.; °C / °F	117°C / 243°F	77°C / 171°F
Hot Water Return Temp.; °C / °F	75°C / 167°F	60°C / 140°F
HW Distribution Pump Flow Capacity; L/s	24 L/s (380 USGPM)	
Energy Centre P2 Hot Water Heating		
Installed Heating Capacity; kW_{th}	15,000 kW_{th}	
Installed Electric Generation; kW_e	1,205 kW_e	
Hot Water Supply Temp.; °C / °F	117°C / 243°F	77°C / 171°F
Hot Water Return Temp.; °C / °F	75°C / 167°F	60°C / 140°F
HW Distribution Pump Flow Capacity; L/s	78 L/s (1,229 USGPM)	
Energy Centre P3 Hot Water Heating		
Installed Heating Capacity; kW_{th}	4,000 kW_{th}	
Hot Water Supply Temp.; °C / °F	117°C / 243°F	77°C / 171°F
Hot Water Return Temp.; °C / °F	75°C / 167°F	60°C / 140°F
HW Distribution Pump Flow Capacity; L/s	21 L/s (333 USGPM)	

2.4 Applicable Codes and Standards

The CES energy centres should be designed with consideration to the latest edition of following codes and standards where applicable:

- ANSI/ASME B31.1 - Power Piping Code
- ANSI/ASME Boiler and Pressure Vessel Code, Section VIII
- CSA B51 – Boiler, Pressure Vessel, and Pressure Piping Code
- CAN/CSA-B139 - Installation Code for Oil Burning Equipment
- CSA B140.7.2 - Oil-fired Steam and Hot Water Boilers for Commercial and Industrial Use
- CSA B149.1 - Natural Gas and Propane Installation Code
- CSA C22.1-2002 – Canadian Electrical Code, Electrical Safety Code, Bulletins, and regulations of the local inspection authority
- The National Fire Safety Code and the Fire Safety Regulations of the Territory.
- Safety Standards for Electrical Equipment, Canadian Electrical Code, Part II.
- The Operating Power Engineers Regulations; as enforced by the territorial building safety authority
- National Building Code

2.5 Energy Centre Description

2.5.1 P-1 Configuration

Hot water will be primarily produced by utilizing spare steam boiler capacity that exists in the hospital steam boiler system. Fuel oil is used in the current boiler system. The surplus steam would be utilized in a steam to a new hot water converter station to produce the required hot water for distribution to the Community heating loads.

Hot water will be pumped to the consumer buildings on a variable flow basis to suit the prevailing load, and the supply temperature will be reset to different values depending on the ambient outdoor temperature.

The major hot water heat production and distribution equipment would be described as follows:

- One (1) - 4 MW_{th} thermal steam converter station with the following characteristics:
    - Shell and tube or gasketed plate heat exchanger
    - Inlet steam control valves
    - Condensate receiver/stabilizing tank
    - Condensate transfer pump
    - Local unit controller
- Hot water distribution pumps with the following characteristics:
    - Two (2) x 100% capacity units (N+1)
    - Base mounted or vertical inline centrifugal pumps;

  - Variable speed drives on pump motors
  - Distribution pump controller
- Thermal Energy Meter with the following characteristics:
  - CSA C900 certified energy metering system
  - Pipe mounted Inline flow sensing element
  - Thermal energy calculator
  - Two pipe mounted temperature sensing elements.
- Expansion Tank with the following characteristics:
  - Single tank (bladderless)
  - Compressed air or nitrogen capping gas
  - Acceptance volume sized to accommodate system volume change.
- Balance of Energy centre systems including:
  - Structure/building (single level fit for purpose) sharing one wall of existing boiler house
  - Electric internal distribution with estimated 100 kVA, 600V power feed from hospital (to be confirmed)
  - Energy centre controls
  - Lighting
  - Utility compressed air from hospital
  - City water, sewer
  - Building HVAC and life safety
  - Fire alarm and sprinklers
  - Water treatment

The steam to hot water conversion station is proposed to be contained in a standalone structure. The structure is assumed to be located immediately adjacent to an outside wall of the existing hospital boiler room.

Electrical power for this steam conversion station is assumed to be supplied from the existing hospital utility infrastructure. This would also include standby power to allow the energy centre to continue operating when a utility power outage occurs.

As the energy centre does not utilize a combustion process to directly generate hot water, air emission controls are not required for the equipment proposed for the P1 energy centre.

The P1 energy centre receives its capacity from an existing boiler that forms part of the existing hospital boiler energy centre. This energy centre would be operated by existing staff.

2.5.2 P-1 Layout

The preliminary layout of the proposed energy centre is depicted in the drawings located in Appendix I .

The preliminary drawings show an assumed general layout of major equipment and services, which provides perspective to the size of the proposed P1 energy centre.

The P1 energy centre has the following distinct areas:

- Steam conversion area
- Distribution pumping area

2.5.3 P-2 Configuration

The P2 energy centre represents the main or baseload energy supply for the proposed CES in Whitehorse. This energy centre would contain heat producing equipment of various configurations.

Hot water boilers coupled with a biomass based combined heat and power (CHP) unit would produce thermal oil, hot water and electricity at this energy centre. Individual boilers will be connected to a main hot water header, and serviced by individual hot water pumps. A hot water boiler header / primary loop “decoupled” piping arrangement is utilized for the hot water piping in the energy centre. This arrangement allows for the individual boilers to operate at a fixed flow, while the primary distribution loop will operate at variable flow. The CHP units would be connected in series with the boilers.

Hot water will be pumped to the consumer buildings on a variable flow basis to suit the prevailing load, and the supply temperature will be reset to different values depending on the ambient outdoor temperature.

The hot water heating equipment will be designed to accommodate the following:

- (2) x 4.0 MW_{th} output non-condensing hot water boilers with the following characteristics:
    - o Fire tube design (ASME Section IV)
    - o Dual Fuel Capability: Fuel Oil primary; Natural gas (LNG) secondary
    - o Maximum supply temperature of 117 °C (243 °F)
    - o NO_x emissions < 200 ppm for fuel oil (to be confirmed)
    - o Fuel to hot water efficiency at 100% capacity – 82.5% (+/-)
    - o Automatic controls providing continuous modulation from 20-100% of load
    - o Fuel oil daytank
- One (1) biomass fuel CHP system with the following characteristics:
    - o Two (2) 3.5 MW_{th} thermal output biomass fuel combustion systems with thermal oil exchange,
    - o 1.2 MW_e, 600 V electrical output (gross) Organic Rankine Cycle (ORC) electric power generator (5.5 MW_{th} thermal output)
    - o 6.0 MW_{th} thermal oil to hot water heat recovery exchanger
    - o Two (2) – 750 kW_{th} exhaust heat recovery economizers

- Thermal oil heat recovery system connecting the biomass combustion system with hot water heat recovery exchanger and ORC generator
- Biomass fuel storage and handling system to provide 72 hour fuel storage for one (1) 3.5 MW_{th} combustor
- Process Heat rejection system
- Exhaust gas particulate cleanup
- Ash collection system
- Biomass system controls
- ORC module controls
- Synchronized operation with the local electric utility grid
- Electrical power export
- Electric utility interconnection and protection

- One (1) Standby/Blackstart generator set with the following characteristics:
  - 190 kW electric output – Size to be confirmed
  - Diesel fuel only
  - Fuel oil daytank
- One (1) Fuel Oil Storage/Handling System:
  - Assumed to be provided externally
  - Fuel oil capacity required: For two - 400 BHP boilers at full load for 24 hours
  - Larger storage is assumed to be provided from the existing Yukon Energy storage facilities
- Two (2) boiler circulation pumps (one per boiler) with the following characteristics:
  - Base mounted or vertical inline constant speed centrifugal pumps, with flow and head to suit individual boiler design.
- One (1) CHP heat recovery circulation pump with the following characteristics:
  - Base mounted or vertical inline constant speed centrifugal pumps, with flow and head to suit individual boiler design.
- Hot water distribution pumps with the following characteristics (based on one primary HW heating loop):
  - Three (3) x 50% capacity units (N+1)
  - Base mounted centrifugal pumps;
  - The pump discharge design pressure will be determined based on the final distribution system hydraulic analysis
  - HW distribution pumps will have a single overall controller and variable frequency drives for each pump.
- Thermal Energy Meter with the following characteristics:
  - CSA C900 certified energy metering system
  - Pipe mounted Inline flow sensing element

  - Thermal energy calculator
  - Two pipe mounted temperature sensing elements.
  - Energy meter provided for main energy centre export and for CHP heat recovery

- Expansion Tank with the following characteristics:
  - Single tank (bladderless)
  - Compressed air or nitrogen capping gas
  - Acceptance volume sized to accommodate system volume change.

- Balance of Energy centre systems including:
  - Structure/building (single level fit for purpose)
  - Electric service and internal distribution (estimated 2 MVA, 600 V to be confirmed)
  - Energy centre controls
  - Lighting
  - Utility compressed air
  - City water, sewer
  - Building HVAC and life safety
  - Fire alarm and sprinklers
  - Water treatment
  - Thermal oil storage and handling
  - Biomass combustor and hot water boiler breeching
  - Exhaust stacks (minimum 12 m height)

The hot water boiler header, as well the primary distribution pumps and piping will be sized for the energy centre design output thermal capacity.

The minimum (summer) hot water supply temperature of the primary community energy loop will be set at 80 °C (176 °F) and will be on a reset schedule governed by ambient outdoor temperature. The maximum (winter) hot water supply temperature will be approximately 117 °C (243 °F).

The maximum supply temperature from the ORC thermal exchanger and biomass hot oil exchanger is 95°C (203°F).

The biomass concepts would see the fuel processed off-site to boiler “spec” grade and delivered in truck trailers to the energy centre site. The trucks would dump the fuel into a “live” storage container. It is assumed that chipping would produce wood particles of somewhat uniform size and fuel quality. This allows for similar designs in fuel storage and augering systems. With either fuel source, special consideration must be taken to accommodate frozen or freezing fuel during the winter months.

The live fuel storage would be covered and attached to the main energy centre and fuel is automatically fed to the boilers as needed. Sufficient storage capacity is provided to meet a three-day peak burn rate (winter long weekend).

The biomass system produces hot water from the fuel for the direct heat options. Flue gas exits via a flue stack that incorporates emissions cleanup equipment would reduce stack emissions of particulate matter to required limits (assumed < 15 mg/nm^3). FVB has included costs for post combustion cleanup equipment to achieve this level of particulate emission.

Bottom ash and fly ash will be automatically collected into an ashbin. Ash is anticipated to be less than 3% by weight for wood chips and 1% for pellet fuel – needs to be confirmed once fuel source is chosen. Biomass ash has many good qualities and may be used for value added purposes, however specific approvals are required.

The distribution system will be provided with the necessary support sub-systems, including water treatment and suitable hot water expansion tank capacity to manage system volume changes as water temperature changes. The in-energy centre pressure piping associated with the hot water system will be schedule 40 welded steel, insulated with fibreglass insulation, and wrapped with either a colour coded polyethylene cover or aluminum cladding.

A bypass fabric filter will be installed across the distribution pumps. 2% of the distribution flow will circulate through the filter at all times.

Each hot water boiler will exhaust to a common breaching/stack system. One main stack is provided for the hot water boilers, while the biomass combustors will each have their own dedicated stack.

The P2 energy centre is proposed to be contained in a standalone fit for purpose industrial structure; see drawing SK-1313-102 in Appendix I . The structure is assumed to be located south of the existing Yukon Energy facilities.

Electrical power for this energy centre would be provided by a new 600 kV (medium voltage) electric service for the energy centre.

Emission controls for this energy centre would take the form of:

- Multi-cyclone particulate scrubber on biomass exhaust
- Electrostatic precipitator on biomass exhaust
- Exhaust stacks with adequate height to meet specified contaminant concentration levels at identified critical receptors.
- Utilize Low or Ultra Low sulphur content fuel oil to minimize boiler SO_x emissions.

2.5.3.1 Operating Staff

The P2 energy centre is assumed to be classified by the Territorial Boiler Safety Authority as a Energy Centre requiring general supervision. Our interpretation of the requirements for general supervision is that a single operator, with the appropriate certification level, be in attendance at the energy centre for 8 hrs per day 7 days per week, when the facility is operational. As this is the main energy centre in the system, it would be expected to operate year round.

We would expect that at a minimum there would be 1.5 full time operating staff on duty at this facility. In addition to the operating staff there would be the requirement for a second person to act as Chief Engineer overseeing all three energy centres. Ultimately, the local Boiler Authority will dictate the staffing requirement following an audit of the facility.

2.5.4 P-2 Layout

The preliminary layout of the proposed energy centre is depicted in the drawings located in Appendix I .

The preliminary drawings show an assumed general layout of major equipment and services, which provides perspective to the size of the proposed P2 energy centre.

The P2 energy centre has the following major areas:

- Hot water boiler area
- Distribution pumping area
- Biomass fuel storage and handling area
- Biomass combustor area
- Organic Rankine Cycle Module
- Biomass exhaust cleanup and ash handling area
- Electrical Room
- Control Room

2.5.5 P-3 Configuration

Hot water would be produced by hot water boiler fired on fuel oil. In this peaking energy centre, a single hot water boiler would be employed. A hot water boiler header / primary loop "decoupled" piping arrangement is utilized for the hot water piping in the energy centre. This arrangement allows for the boiler to operate at a fixed flow, while the primary distribution loop will operate at variable flow.

Hot water will be pumped to the consumer buildings on a variable flow basis to suit the prevailing load, and the supply temperature will be reset to different values depending on the ambient outdoor temperature.

The hot water heating equipment will be designed to accommodate the following:

- 1 x 4.0 MW_{th} output non-condensing hot water boiler with the following characteristics:
  - o Multi-pass Fire tube design (for ease of fireside tube cleaning when primary fuel is oil)

- Fuel oil fired only
- Maximum supply temperature of 117 °C (243 °F)
- Maximum boiler water side ΔT= 13 °C
- NO_x emissions: 200 ppm corrected to 3% oxygen – to be confirmed
- Fuel to hot water efficiency at 100% capacity – 82.5% (+/-)
- Automatic controls providing continuous modulation from 20-100% of load
- Inlet air silencers will be provided on the forced draft fans.

- 1 x boiler circulation pump (one per boiler) with the following characteristics:
    - Base mounted or vertical inline constant speed centrifugal pumps, with flow and head to suit individual boiler design.
- Hot water distribution pumps with the following characteristics:
    - 1 x 100% capacity
    - Base mounted or vertical inline centrifugal pumps;
    - The pump discharge design pressure will be determined based on the final distribution system hydraulic analysis
    - HW distribution pumps will have a single overall controller and variable frequency drives for each pump
- Thermal Energy Meter with the following characteristics:
    - CSA C900 certified energy metering system
    - Pipe mounted Inline flow sensing element
    - Thermal energy calculator
    - Two pipe mounted temperature sensing elements
- Expansion Tank with the following characteristics:
    - Single tank (bladderless)
    - Compressed air or nitrogen capping gas
    - Acceptance volume sized to accommodate downtown system volume change
- Standby Generator with the following characteristics:
    - Approximately 100 kW, 600V-3 phase-60Hz electric output
    - No. 2 oil fuel, reciprocating engine driven
- Fuel Oil System
    - Fuel oil storage sized for 7 days boiler operation at full load
    - Fuel oil pumps to be duplex configuration
    - Double walled storage tank above ground with containment/barrier dyke
- Balance of Energy centre systems including:
    - Structure/building (single level fit for purpose)
    - Electric service and internal distribution (estimated 300 kVA, 600V to be confirmed)
    - Energy centre controls

  - Lighting
  - Utility compressed air
  - City water, sewer
  - Building HVAC and life safety
  - Fire alarm and sprinklers
  - Water treatment
  - Boiler breeching
  - Boiler Exhaust stack (Minimum 12 m height)
  - The P3 energy centre is proposed to be contained in a standalone structure. The structure is assumed to be located in the downtown.
  - Electrical power for this energy centre would be provided by a new 600 V electric service for the energy centre.

- Balance of Energy centre systems including:
  - Emission controls for this energy centre would take the form of:
  - Boiler Burner with FGR or Forced FGR
  - Utilize Low or Ultra Low sulfur content fuel oil to minimize SO_x emissions.
  - Exhaust stack with adequate height to meet specified contaminant concentration levels at identified critical receptors.

The P3 energy centre is assumed to be classified by the Territorial Boiler Safety Authority as a Energy Centre requiring general supervision. Our interpretation of the requirements for general supervision is that a single operator, with the appropriate certification level, be in attendance at the energy centre for 8 hrs per day 7 days per week, when the facility is operational. As this is a peaking energy centre, it would be expected that the energy centre would operate infrequently and only in the winter months.

Ultimately, the local Boiler Authority will dictate the staffing requirement following an audit of the facility.

2.5.6 P-3 Layout

The preliminary layout of the proposed energy centre is depicted in the drawings located in Appendix I .

The preliminary drawings show an assumed general layout of major equipment and services, which provides perspective to the size of the proposed P3 energy centre.

The P3 energy centre has the following major areas:

- Boiler area
- Distribution Pumping area
- Standby Generator area
- Electrical
- Fuel storage

2.5.7 Piping Design

The process and utility piping design requirements are summarized as follows:

- Process Hot water piping would be designed and installed to ASME B31.1 piping standards. The process hot water and compressed air piping will be design registered with the Safety Authority if required.
- Natural gas piping will be designed in accordance with the CSA B149.1 Natural gas installation code and local fuel safety authority.
- Fuel oil piping and storage will be designed in accordance with the CSA B139 Oil Installation Code and local fuel safety authority.
- Building domestic water and internal heating systems will be designed and installed to ASME B31.9 piping standards.

2.6 Energy Centre Staffing

The requirements for operating staff at the proposed hot water community energy Centres are dictated by the Yukon Boiler and Pressure Vessel Act.

The proposed energy centres would produce hot water at a maximum condition of 121 °C and 1,100 kPag. Based on these process limits, the Act defines the proposed facilities as “Energy Centres”, and subject to “General Supervision”.

FVB’s interpretation of “General Supervision” is a energy centre would require the attendance of a power engineer with appropriate certification for 8 hours per day, 7 days a week.

With respect to the energy centres proposed in FVB’s study, the P1 energy centre is assumed to be monitored by existing hospital boiler room operators. The P2 energy centre would require general supervision by an appropriately qualified operator. The peaking energy centre P3, would also require general supervision by an appropriately qualified operator, but only when the energy centre is operational.

It is also assumed that a single chief operating engineer would be assigned to cover the P2 and P3 energy centres.

As identified in the legislation, despite the minimum staffing levels and competencies implied or indicated by the published regulations, the actual number of operators that must attend a energy centre site and their required certification level is at the sole discretion of the Territorial boiler safety authority.

3 LNG Concept Design Basis

FVB Energy Inc. (FVB) has also been asked to outline the LNG concept design basis of the new CES proposed for the City of Whitehorse, YT. This document will serve as the preliminary technical reference for the “LNG” system’s design.

Based on the direction received from Yukon Energy, it is understood that Whitehorse will require additional electricity generation for the power grid. This concept tries to define whether thermal and electrical cogeneration from LNG fuelled engines is an attractive option for the community energy concept.

This system shares the same general concept as the biomass concept, except for the changes to Energy Centre 2.

3.1 Energy Production Centres

3.1.1 General

There are no changes to the other two thermal energy centres (P1 & P3) proposed in the biomass design basis document.

The second energy centre P2, would be established south of the current Yukon Energy facilities to serve as the main heat producing facility for the Community system. The P2 energy centre would be operated continuously in a baseload operating role.

It is assumed that the LNG cogeneration units are electrical load following, and that as electricity is required in the winter months, this facility would create both heat and power for approximately 4,890 hours from October to April. These engines will run at full output to maximize electricity generation. Heat that is not required for the system will be rejected to atmosphere.

The P2 LNG peaking boilers provide peak capacity as required, as well as baseload heat during those times when the cogeneration units are not running.

Preliminary drawings for the proposed LNG cogeneration energy centre can be found in Appendix I and include the following drawings:

- Energy Centre P2 – LNG Cogen Flow Schematic
- Energy Centre P2 – LNG Boiler Flow Schematic
- Energy Centre P2 – LNG Concept Preliminary Equipment Layout
- Energy Centre P2 – LNG Concept Preliminary Electrical Single Line Diagram

The remaining energy centre schematics are identical to the Biomass concept.

3.1.2 Overall Design Parameters

The following tables outline the design data applicable to Energy Centre 2. Further design data can be found in Table 2 and Table 3 in the biomass concept design basis.

Table 4 - Energy Centre Operating Design Criteria

Description	Winter	Summer / Shoulder Months
Energy centre 2 Hot Water Heating		
Installed Heating Capacity; kW_{th}	14,100 kW_{th}	
Installed Electric Generation; kW_e	3,305 kW_e	
Hot Water Supply Temp.; °C / °F	117°C / 243°F	77°C / 171°F
Hot Water Return Temp.; °C / °F	75°C / 167°F	60°C / 140°F
HW Distribution Pump Flow Capacity; L/s	78 L/s (1,229 USGPM)	

3.2 Applicable Codes and Standards

The CES Energy Centres will be designed with consideration to the latest edition of following codes and standards where applicable. Details of relevant codes can be found in the biomass technical concept design basis.

3.3 Energy Centre Description

3.3.1 P-2 Configuration

The P2 energy centre represents the main or baseload energy centre for the proposed CES in Whitehorse.

Hot water boilers coupled with a LNG fuelled reciprocating engine combined heat and power (CHP) unit would produce hot water and electricity at this energy centre. Individual boilers will be connected to a main hot water header, and serviced by individual hot water pumps. A hot water boiler header / primary loop "decoupled" piping arrangement is utilized for the hot water piping in the CEC. This arrangement allows for the individual boilers to operate at a fixed flow, while the primary distribution loop will operate at variable flow. The CHP heat recovery circuits would be connected in series with the boilers.

Hot water will be pumped to the consumer buildings on a variable flow basis to suit the prevailing load, and the supply temperature will be reset to different values depending on the ambient outdoor temperature.

The hot water heating equipment will be designed to accommodate the following:

- (2) X 4.0 MW_{th} output non-condensing hot water boilers with the following characteristics:
  - Flexible Water tube design (ASME Section IV)
  - Dual Fuel Capability: Natural gas (LNG) primary; Fuel oil secondary
  - Maximum supply temperature of 117 °C (243 °F)
  - NO_x emissions < 46 ppm corrected to 3% oxygen (LNG fuel only)
  - Fuel to hot water efficiency at 100% capacity – 82.5% (+/-)
  - Automatic controls providing continuous modulation from 20-100% of load

  - LNG vapourized and pre-heated using exchanger with community energy water
  - Fuel oil day tank to provide storage capacity to operate 2 x 400 BHP boilers at full load for 12 hours

- Two (2) LNG fuelled cogeneration engine with the following characteristics:
  - 2 X 3.05 MW_{th} thermal output LNG fuel combustion engines comprising of heat recovery from:
    - Mixture Intercooler – 1st Stage heat exchange
    - Lube oil heat exchange
    - Engine jacket water heat exchange
    - Heat exchange from exhaust gas with bypass control
  - 2 X 3.36 MW_e, (power factor of 0.8) 4,160 V electrical output (gross)
  - LNG vapourized and pre-heated using exchanger with heat exchange from the 2nd Stage Intercooler
  - Exhaust gas silencer
  - Engine system controls
  - Synchronized operation with the local electric utility grid
  - Electrical power export
  - Electric utility interconnection and protection

- One (1) Standby/Blackstart generator set with the following characteristics:
  - 250 kW electric output – Size to be confirmed
  - Diesel fuel only
  - Fuel oil daytank

- One (1) engine heat rejection system per engine with the following characteristics:
  - Glycol cooling loop
  - Freeze protection pumps
  - Exterior mounted radiators

- Two (2) boiler circulation pumps (one per boiler) with the following characteristics:
  - Base mounted or vertical inline constant speed centrifugal pumps, with flow and head to suit individual boiler design.

- One (1) CHP heat recovery circulation pump with the following characteristics:
  - Base mounted or vertical inline constant speed centrifugal pumps, with flow and head to suit individual boiler design.

- Hot water distribution pumps with the following characteristics (based on one primary HW heating loop):
  - Three (3) x 50% capacity units (N+1)
  - Base mounted centrifugal pumps;

  - The pump discharge design pressure will be determined based on the final distribution system hydraulic analysis
  - HW distribution pumps will have a single overall controller and variable frequency drives for each pump.

- Thermal Energy Meter with the following characteristics:
  - CSA C900 certified energy metering system
  - Pipe mounted Inline flow sensing element
  - Thermal energy calculator
  - Two pipe mounted temperature sensing elements.
  - Energy meter provided for main energy centre export and for CHP heat recovery

- Expansion Tank with the following characteristics:
  - Single tank (bladderless)
  - Compressed air or nitrogen capping gas
  - Acceptance volume sized to accommodate system volume change.

- Balance of Energy centre systems including:
  - Structure/building (single level fit for purpose industrial building)
  - Electric service and internal distribution (estimated 10 MVA, 4.16kV to be confirmed)
  - Electrical substation (estimated 4.16 kV/600V; 2000 kVA to be confirmed)
  - Energy centre controls
  - Lighting
  - Utility compressed air
  - City water, sewer
  - Building HVAC and life safety
  - Fire alarm and sprinklers
  - Water treatment
  - Lube oil storage and handling
  - CHP engine and hot water boiler breeching
  - Exhaust stacks (minimum 14.7 m height)

The hot water boiler header, as well the primary distribution pumps and piping will be sized for the energy centre design output thermal capacity.

The minimum (summer) hot water supply temperature of the primary CES loop will be set at 80 °C (176 °F) and will be on a reset schedule governed by ambient outdoor temperature. The maximum (winter) hot water supply temperature will be approximately 117 °C (243°F).

The distribution system will be provided with the necessary support sub-systems, including water treatment and suitable hot water expansion tank capacity to manage system volume changes as water temperature changes. The in-energy centre pressure piping associated with the hot water system will be schedule 40 welded steel, insulated with fibreglass insulation, and wrapped with either a color coded polyethylene cover or aluminum cladding.

A bypass fabric filter will be installed across the distribution pumps. 2% of the distribution flow will circulate through the filter at all times.

Each hot water boiler will exhaust to a common breaching/stack system. One main stack is provided for the hot water boilers, while each CHP unit will each have its own dedicated stack.

The P2 energy centre is proposed to be contained in a standalone structure. The structure is assumed to be located south of the existing Yukon Energy facilities.

Electrical power for this energy centre would be provided by a new 4.16 kV (medium voltage) electric service for the energy centre.

Emission controls for this energy centre would take the form of:

- Low NO_x burner with FGR on the hot water boilers
- Exhaust stacks with adequate height to meet specified contaminant concentration levels at identified critical receptors

The P2 energy centre is assumed to be classified by the Territorial Boiler Safety Authority as a Energy Centre requiring general supervision. Our interpretation of the requirements for general supervision is that a single operator, with the appropriate certification level, be in attendance at the energy centre for 8 hrs per day 7 days per week, when the facility is operational. As this is the main energy centre in the system, it would be expected to operate year round.

We would expect that at a minimum there would be 1.5 FTE operating staff on duty at this facility. In addition to the operating staff there would be the requirement for a second person to act as Chief Engineer overseeing all three energy centres.

Ultimately, the local Boiler Authority will dictate the staffing requirement following a facility audit.

3.3.2 P-2 Layout

The preliminary layout of the proposed energy centre is depicted in the drawings located in Appendix I . The preliminary drawings show an assumed general layout of major equipment and services, which provides perspective to the size of the proposed P2 energy centre.

The P2 energy centre has the following major areas:

- Hot water boiler area
- Distribution pumping area
- LNG CHP Engines
- Electrical Room
- Control Room

4 Buried Distribution Piping System Design Basis

4.1 Routing Selection

The pipeline routing was selected using existing right-of-ways and infrastructure. The general intent is to locate lines near customers to minimize capital costs and the ecological footprint of this project. Any road that has been recently resurfaced was avoided if possible.

All pipe distances and routing is estimated based on drawings provided. Actual routing is to be clarified in the design stages based on survey results of existing utility infrastructure.

Branch lines are assumed to connect via the shortest path to existing building mechanical rooms. For those buildings not visited, the locations are estimated.

The routing takes advantage of existing river crossings via the existing foot bridge by the Yukon Energy power station and along the underside of the Yukon River Bridge. For the purposes of this report, bridge loads were assumed able to withstand the additional weight of the distribution pipes and hangars. The DPS routing also crosses Robert Service Way.

4.2 Phasing

The pipe work is divided into five distinct phases, based on the amount of trench meters that can be installed within a construction season. All attempts have been made to provide redundancy in thermal capacity, while delaying energy centre development until the capacity is required. This allows for capital flow from the customer base to help offset capital expenditures. Schematics showing the phased pipe routing and typical details can be found in Appendix II .

In the first phase, the piping would extend from the hospital energy centre along Hospital Road and Lewes Boulevard up to the Selkirk Elementary School.

Phase 2 piping is proposed to extend down Lewes Boulevard, and down Nisutlin Drive. This routing includes crossing the Yukon River and crossing Robert Service Way to connect to the proposed energy centre P2 location. The scenario assumes using the existing foot bridge by the Yukon Energy Sub-Station, as shown in the figure below.

Figure 1 - Existing Foot Bridge by Yukon Energy Sub-station

With the base capacity at energy centre P2 established, phase 3 connects the CES to the energy dense downtown zone, supplying thermal energy to buildings located along First and Second Avenue. Phase 3 includes crossing the Yukon River using the underside of the Yukon River Bridge, as shown in the figure below.

Figure 2 - Underside of Yukon River Bridge

Phase 4 continues developing the downtown core with lines following Steele Street and down Fourth Avenue. This phase includes connecting the distribution piping system to the proposed downtown energy centre P3.

The final phase is proposed to connect the remainder of the Riverdale customers.

Final routing of the distribution piping would be established during the design phase of the project and would need to take into account energy centre location and actual customer buildings that commit to the CES. Coordination of the routing with the City of Whitehorse must also be completed before finalizing the piping network design.

4.3 Pipe Sizing

Sizing of the distribution piping was an iterative process that involved providing peak capacity to all the consumers connected to the system. A diversification factor of 85% was used on the main pipelines to account for the differing peaks of various types of buildings. The following assumptions were used as a basis for the pipe sizing criteria:

- Assumed pressure loss = 200 Pa/m
- Assumed supply and return water temperature differential = 40°C
- Ambient ground temperature of -10°C

These assumptions were inputs for a piping network analysis program, Termis, which was used to simulate a steady state flow analysis for pipe sizing. To properly determine the full pipe size of each section, three scenarios were considered for the three energy centres in the system, as seen in the table below.

Table 5 - DPS Sizing from Energy Centre Capacity Scenarios

Scenario	Energy Centre 1 Capacity (MW)	Energy Centre 2 Capacity (MW)	Energy Centre 3 Capacity (MW)	Total Energy Centre Capacity (MW)	Total System Demand (MW)	Heat Loss (MW)
1	1.9	13	0	14.9	14.45	0.45
2	0	13	1.9	14.9	14.45	0.45
3	4	7	3.9	14.9	14.45	0.45

- Scenario 1 assumes full output from Energy Centre 2 with Energy Centre 1 making up the rest of the needed capacity.
- Scenario 2 assumes full output from Energy Centre 2 with Energy Centre 3 making up the rest of the needed capacity.
- Scenario 3 assumes the alternative energy source is non-operational, thus Energy Centre 2 outputs 7 MW and Energy Centre 1 is assumed at full output with Energy Centre 3 making up the rest of the needed capacity.

From these three scenarios the largest pipe sizes were taken from each and amalgamated into one system that can provide full capacity under each loading condition. This process for sizing was to ensure that if the alternative energy source or either Energy Centre 1 or 3 were to be offline during peak conditions, the distribution piping system would be able to deliver the required capacity from the other energy centres to the customers.

4.4 Insulation

Due to the high cost of energy and the colder northern climate in Whitehorse, different thicknesses of insulation were considered for the piping system. After estimating the annual heat loss for each type of insulation, the capital costs were compared with the energy savings for the thicker insulation options. Based on the analysis, it is recommended that the distribution system be installed using the more insulated Logstor Series 2 pipe. Using Series 2 produced an estimated 532 MWh of annual energy savings and an incremental installation cost of approximately $951,000. Assuming the cost of energy production is $100/MWh, the simple payback for installing Series 2 versus Series 1 piping is 17.9 years.

4.5 Piping Material

It is proposed that the primary side underground heating lines will be European type thin walled steel pipes factory pre-insulated with polyurethane foam insulation (PUR) and a High-Density Polyethylene (HDPE) outer jacket. This style of buried piping system has been in use specifically for CESs in Europe and Asia for over 40 years. FVB have been designing buried steel distribution piping systems for projects in Canada for the last twenty years, with this type of product as the basis. The heating system would be installed as a fully welded system. The interior building primary heating piping will be A53B standard weight (Sch. 40) steel pipes insulated with fibreglass insulation and a PVC or aluminum outer jacket.

4.6 Design Conditions

Primary piping to be installed will meet ASME Code for Pressure Piping B31.1.

- Peak operating primary supply temperature of 117°C maximum with a return temperature of 77°C (peak temperature difference of 40°C). Reset schedule for “off-peak” conditions to be implemented.
- Primary Design Temperature: 121°C (250°F)
- Primary Design Pressure: 16 bar (232 psig)

4.7 Installation

In general, the distribution piping system would be installed using open trench construction methods. Some busy street crossings will be crossed with non-destructive methods. Heating pipes would be installed side by side in the trench. See cross-section drawing below. Pipes are embedded in compacted well-graded sand. Open trench width is dependent on the pipe size. For example with mainlines consisting of 200 mm (8”) heating pipes, the trench width would be a maximum of approximately 1250 mm wide. Trench widths for smaller or larger sized piping would be reduced or increased accordingly. Trench cutbacks in unpaved areas are based on a 1:1 slope for depths greater than 1.0 meters.

Native soils will be returned and compacted in the trench to complete filling up to the underside of the roadbed. Trench construction and all work within the streets will conform to City and/or Regional requirements. Generally, all reinstatement is to an “as was” condition and/or to meet adjacent conditions.

Minimum acceptable buried depth beneath roadways is 600 mm and 450 mm beneath grassed areas. Depth of bury, in general averages between 800mm to 1200mm but varies based on existing utilities in the vicinity. Piping in roadways will be designed in coordination with the City of Whitehorse's standards for utilities.

Surface restoration will be to restore original condition or to meet the City of Whitehorse standards.

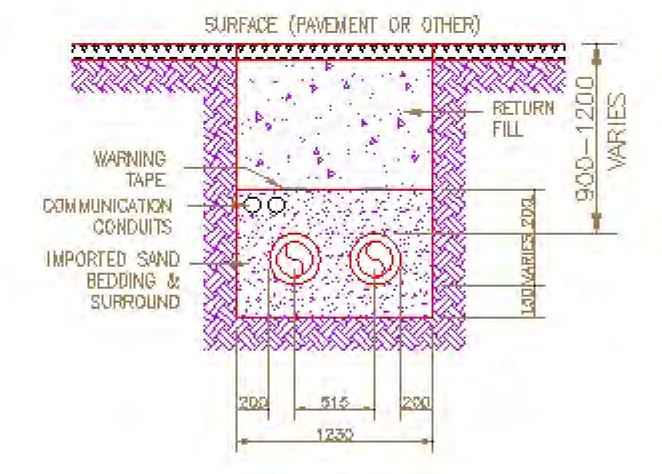


Figure 3 - Typical Cross-section of Pipe Trench

4.8 Communication

With a communication network, each customer building can be monitored and or adjusted from a central location (typically the Energy Centre). This is accomplished with the installation of electrical or fiber optic cables inside communication conduits to form a communication network. Typically, two buried communication conduits are installed with shielded multi-pair communication cables inside the conduits. An option that the Owner may want to consider is to upgrade the communication to fibre optics cable. This may require additional engineering and capital cost but should be considered, especially for a large distribution system and if other uses for the fibre system can be incorporated. The communication cable is to be terminated at each customer. The main distribution pumps at the Energy Centre will be controlled based on differential pressure signals from the furthest points in the distribution system.

5 Energy Transfer Stations Design Basis

5.1 General

The Energy Transfer Station (ETS) is the physical point of interface between the CES and the customer buildings' internal heating and domestic hot water systems. Typically one ETS is installed in each building and would replace the existing boilers as the heat source for the building. A basic ETS consists of isolating valves, heat exchangers, automated control valves, electronic controls, and an energy meter. The ETS piping is welded standard weight carbon steel piping with fibreglass insulation and PVC jacketing. For the building side piping, it is expected to match the existing piping as currently installed.

The buildings will be "indirectly" connected to the primary hot water distribution system. This means that each building's internal heating and domestic hot water systems (secondary side) are isolated from the CES distribution system (primary side) by means of a heat exchanger (brazed plate for heating and double-walled plate & frame for domestic hot water). A separate heat exchanger is normally provided for the domestic hot water load so that the main heating system is not required to operate in the summer.

5.2 Design Temperatures and Pressures

The community energy centres will supply up to 117°C (243°F) on the primary side to each building ETS and return 75°C (167°F) hot water during peak periods. Primary piping will meet ASME Code for Pressure Piping B31.1. The design pressure is 1,600 kPa (~232 psig). To achieve these temperature parameters, the building's internal heating system would supply water at a temperature of up to a maximum of 82°C (180°F) and returning a maximum of 70°C (160°F). These building design conditions need to be verified at the design stage. The building side secondary piping will be designed to match the existing design pressure and temperature criteria.

5.3 Location

The energy transfer stations typically require a room size of less than 10 m^2. Some key factors that dictate the room size dimensions include:

- Room height, if low ceiling height
- Complexity of the connecting systems
- Building connected load

Typically, the energy transfer stations are placed in existing mechanical rooms, and utilize the space of one of the boilers. For new buildings not yet constructed, a basement mechanical room with an exterior wall near the buried distribution piping system route is requested for the location of the ETS in order to minimize the amount of service piping.

It is preferable to locate the ETS in a basement or ground floor mechanical room to ensure that the building elevations do not put unwanted static pressure limitations on the entire system. For this reason, it is not recommended to locate the ETS more than 4 storeys above grade. As a result, during design phase, the location of the ETS must be carefully considered before deeming a building technically feasible for connection.

5.4 Heating and Domestic Hot Water Equipment Capacities

The heating requirements of each building have been determined based on existing equipment capacities, fuel usage, and FVB building data for other similar types of buildings. Conceptually, heat exchangers are sized with 20% redundancy for typical buildings. For the hospital, two heat exchangers at 70% of load were assumed for each system connection providing an overall redundancy of 40%.

5.5 Domestic Hot Water Configurations

In order to minimize system return temperatures, instantaneous domestic hot water heating is preferred with a three-way mixing control valve on the domestic hot water supply line. If the building design requires storage, a buffer or storage tank can be incorporated.

5.6 Energy Metering

How much heat the customer needs to “buy” from the CES is measured by an energy meter. The energy meter on each ETS is made up of a flow meter, two temperature sensors (supply and return) and an energy calculator. This equipment is located on the primary side of the energy transfer station and continuously meters the building thermal energy usage as well as the instantaneous thermal load. The meters could be connected to a centralized monitoring and control system for remote readout capability. The meters that would be specified for this project should meet existing international standards (OIML R75 and EN1434) and CSA C900 standard for revenue class thermal energy metering. There are limited suppliers of heat energy meters available for purchase in Canada that meet the technical requirements of the aforementioned standards.

Each building’s heat usage will be bulk metered at the Energy Transfer Station (i.e. no sub-metering is expected).

5.7 Controls and Reset Schedule

The ETS controller senses if the building heating needs are being met based on the supply and return temperatures of the building heating system. The controller satisfies the heating demand by modulating the two-way control valves located on the primary side of the ETS. The CES temperatures are controlled based on the building side supply and return temperatures. These must be reset based on outdoor air temperature so that the CES temperatures can also be reset. The maximum building side supply temperature expected is 82°C (180°F) for heating and the minimum can be as low as ambient in summer, if there is no reheat in the building system. At the same time the building side return temperature will be limited to a maximum of 70°C (160°F). The lowest allowable CES supply temperature will be determined by the buildings’ requirements during off-peak seasons, but it is expected to be as low as 70°C (158°F).

In order for the CES to operate as efficiently as possible, each building must return the lowest possible temperatures from the buildings' terminal end devices (such as heating coils). The most effective way to achieve this is by designing for variable flow and resetting the hot water and air supply temperatures based on the ambient conditions. End devices should be controlled by either a two-way modulating or by a three-way mixing valve (pumped configuration) to maximize the temperature differential across each device.

5.8 Communication

With the installation of a communication network, each building's operating conditions can be monitored from a central location such as the energy centre.

5.9 Division of Responsibility

5.9.1 Typical Existing Buildings

Typically, the Community Energy Utility will provide, own and maintain all piping & equipment up to the secondary flanges of the heat exchanger while the building owner will be responsible for owning, and maintaining the building secondary piping, pumping and necessary control equipment. As well, the Community Energy Utility typically provides and installs the components and piping on the secondary side necessary to connect into the existing building heating systems.

5.10 Examples of Twelve Building Connections

Twelve buildings were selected for the development of preliminary building heating schematics. Most of these buildings were visited and basic heating configuration and installed equipment noted. The following buildings have basic descriptions of each building's heating system, along with preliminary heating schematics attached in Appendix III :

1. Whitehorse General Hospital (SK-1313-001A & B)
2. Thomson Centre (SK-1313-002)
3. Education Building (SK-1313-003)
4. Yukon Territory Government Administration Building (SK-1313-004)
5. City Hall / Fire Hall (SK-1313-005)
6. High Country Inn (SK-1313-006)
7. Yukon Energy Office (SK-1313-007)
8. Yukon Energy P125 Hydro Generating Facility (SK-1313-008)
9. Law Courts (Yukon Justice Building) (SK-1313-009)
10. Whitehorse Elementary School (SK-1313-010)
11. Elijah Smith Federal Building (SK-1313-011)
12. Closeleigh Manor (SK-1313-012)

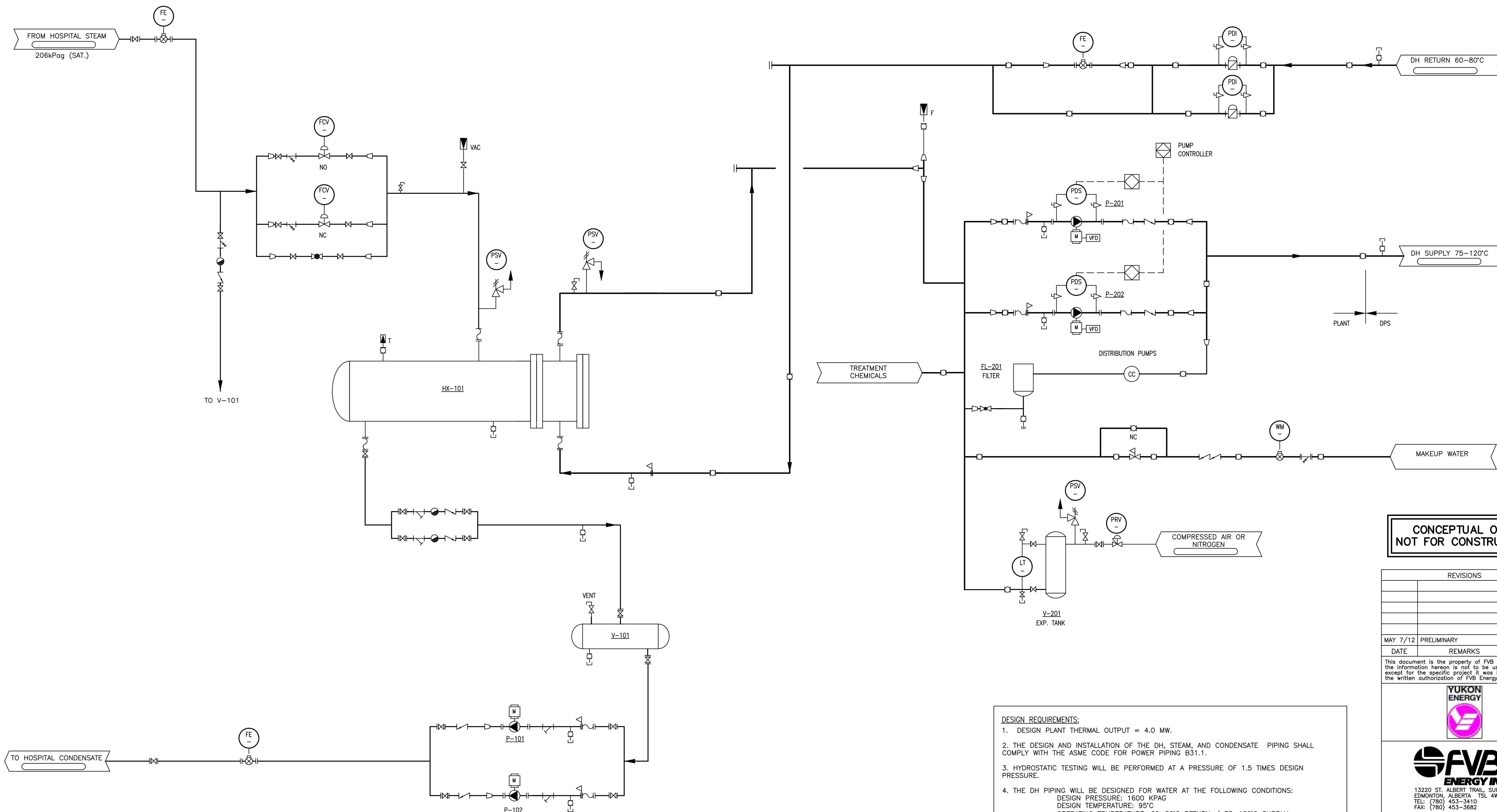
As well, a typical building connection schematic was developed as a basis for other existing buildings to be connected to the CES.

5.11 Building Heating Systems Incompatible to Community Energy

Any systems that run directly on steam, such as humidification and sterilization, cannot be directly connected to the proposed CES. The hospital high pressure steam boilers that currently supply the steam for sterilization will remain in operation after the connection to the CES.

Direct oil of propane fired terminal units, such as rooftop units of unit heaters are not typically connected to the CES unless they are converted to hot water.

Appendix I - Energy Centre Schematic and Layout Package



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

DESIGN REQUIREMENTS:

1. DESIGN PLANT THERMAL OUTPUT = 4.0 MW.

2. THE DESIGN AND INSTALLATION OF THE DH, STEAM, AND CONDENSATE PIPING SHALL COMPLY WITH THE ASME CODE FOR POWER PIPING B31.1.

3. HYDROSTATIC TESTING WILL BE PERFORMED AT A PRESSURE OF 1.5 TIMES DESIGN PRESSURE.

4. THE DH PIPING WILL BE DESIGNED FOR WATER AT THE FOLLOWING CONDITIONS:
DESIGN PRESSURE: 1600 KPAG
DESIGN TEMPERATURE: 95°C
OPERATING TEMPERATURE: 60-80°C RETURN / 75-120°C SUPPLY

5. THE STEAM PIPING WILL BE DESIGNED FOR STEAM AT THE FOLLOWING CONDITIONS:
DESIGN PRESSURE: TBA
DESIGN TEMPERATURE: TBA
OPERATING PRESSURE/TEMPERATURE: TBA

6. THE CONDENSATE PIPING WILL BE DESIGNED FOR STEAM AT THE FOLLOWING CONDITIONS:
DESIGN PRESSURE: TBA
DESIGN TEMPERATURE: TBA
OPERATING PRESSURE/TEMPERATURE: TBA

HX-101
HEAT EXCHANGER (100%)
DUTY: 4.0 MW

V-101
CONDENSATE RECEIVER
ID:
LENGTH:
DESIGN PRESSURE:
DESIGN TEMPERATURE:

V-201
HW EXPANSION TANK XX USGAL

P-101/102
CONDENSATE RETURN PUMPS
FLOW:
HEAD:

P-201/202
DISTRIBUTION CENTRIFUGAL PUMPS 2 @ 100%
FLOW: XXX l/s
HEAD: XX.X m
MOTOR: 575/3/60, XX hp.

FL-201
SIDESTREAM FILTER

REVISIONS		
MAY 7/12	PRELIMINARY	A
DATE	REMARKS	NO.

YUKON ENERGY

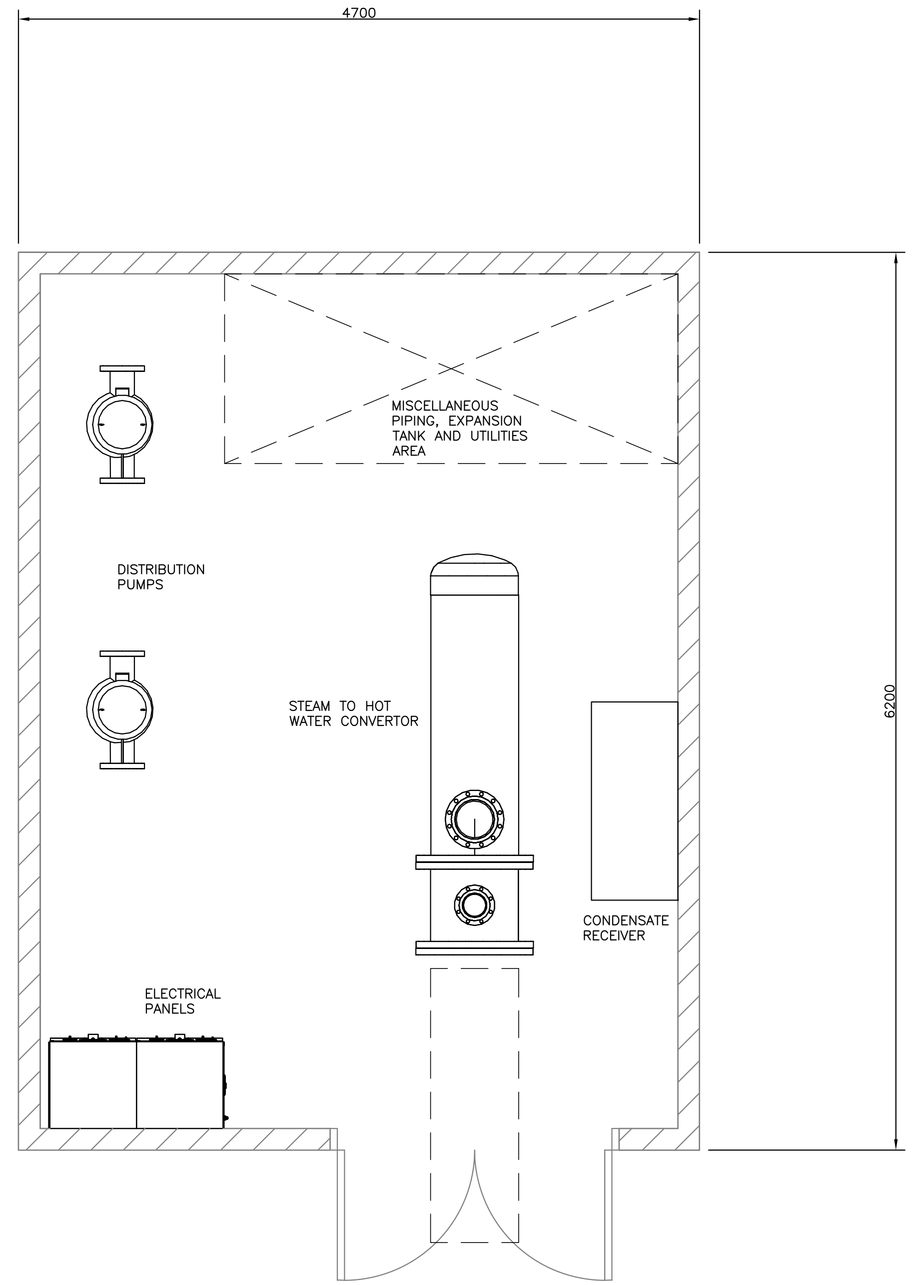
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-1
STEAM CONVERTOR STATION
SCHEMATIC

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: SK-1313-001



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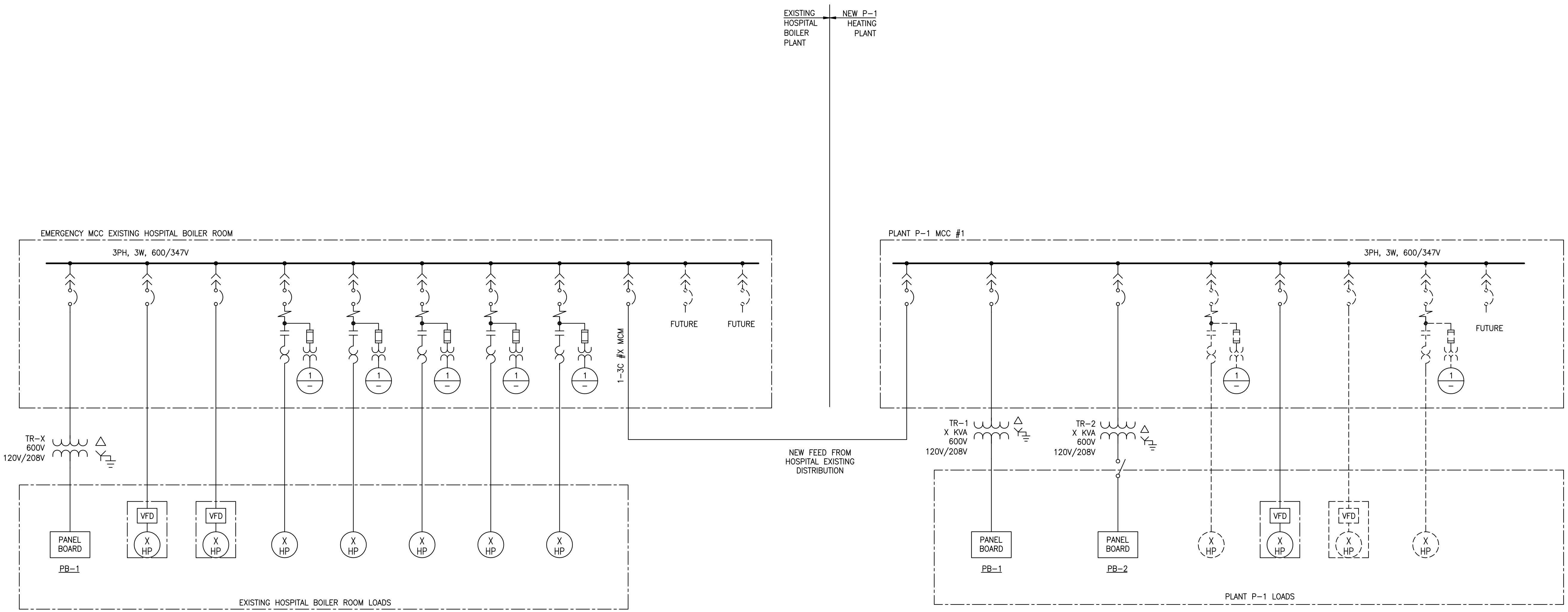
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-1
STEAM CONVERTOR STATION
PRELIMINARY EQUIPMENT LAYOUT

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: SK-1313-101



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DATE	REMARKS	NO.

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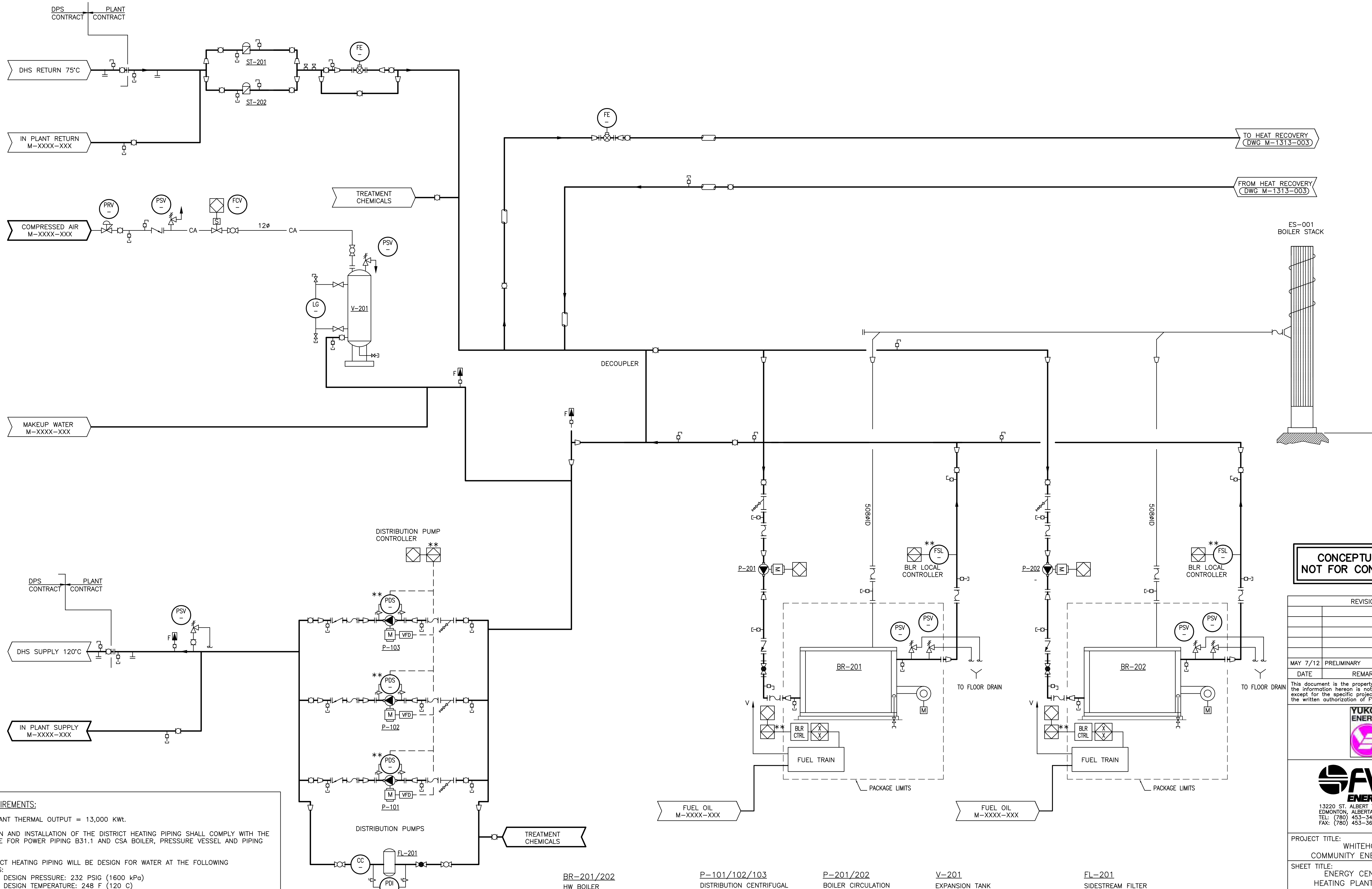
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
PLANT P-1
ELECTRICAL SINGLE LINE DIAGRAM

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: E-1313-001



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

DESIGN REQUIREMENTS:

1. DESIGN PLANT THERMAL OUTPUT = 13,000 KWt.
2. THE DESIGN AND INSTALLATION OF THE DISTRICT HEATING PIPING SHALL COMPLY WITH THE ASME CODE FOR POWER PIPING B31.1 AND CSA BOILER, PRESSURE VESSEL AND PIPING CODE B51.
3. THE DISTRICT HEATING PIPING WILL BE DESIGN FOR WATER AT THE FOLLOWING CONDITIONS:
   DESIGN PRESSURE: 232 PSIG (1600 kPa)
   DESIGN TEMPERATURE: 248 F (120 C)
   OPERATING TEMPERATURE: 243 F (117 C)
4. HYDROSTATIC TESTING WILL BE PERFORMED AT A PRESSURE OF 1.5 TIMES DESIGN.
5. OVERPRESSURE PROTECTION WILL BE PROVIDED AT EACH BOILER; RELIEF VALVE SETTING=160 PSIG (1103 kPa).

BR-201/202
HW BOILER
DUTY: 4.0 MW (408 BHP)
SUPPLIED BY:

P-101/102/103
DISTRIBUTION CENTRIFUGAL PUMPS
FLOW: XX.X L/s (each)
HEAD: XX.X m
MOTOR: XX kW
SUPPLIED BY:

P-201/202
BOILER CIRCULATION PUMP
FLOW: XX L/s
HEAD: XX.X m
MOTOR: X.X kW

V-201
EXPANSION TANK
TANK VOL: XXX L
DESIGN PRESSURE: XXX kPag & XXX°C

FL-201
SIDESTREAM FILTER

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YUKON ENERGY

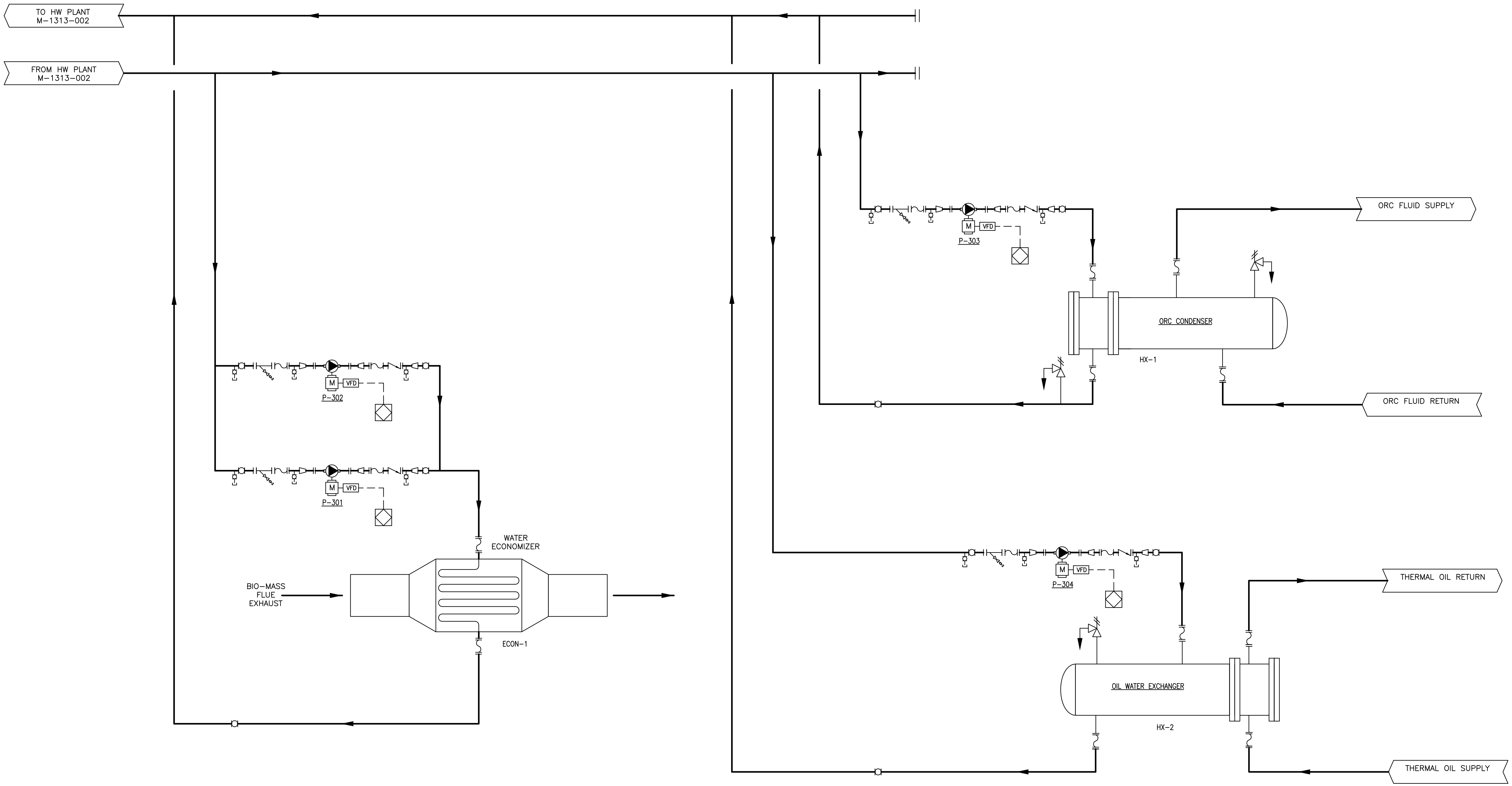
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-2
HEATING PLANT SCHEMATIC

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: SK-1313-002



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13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

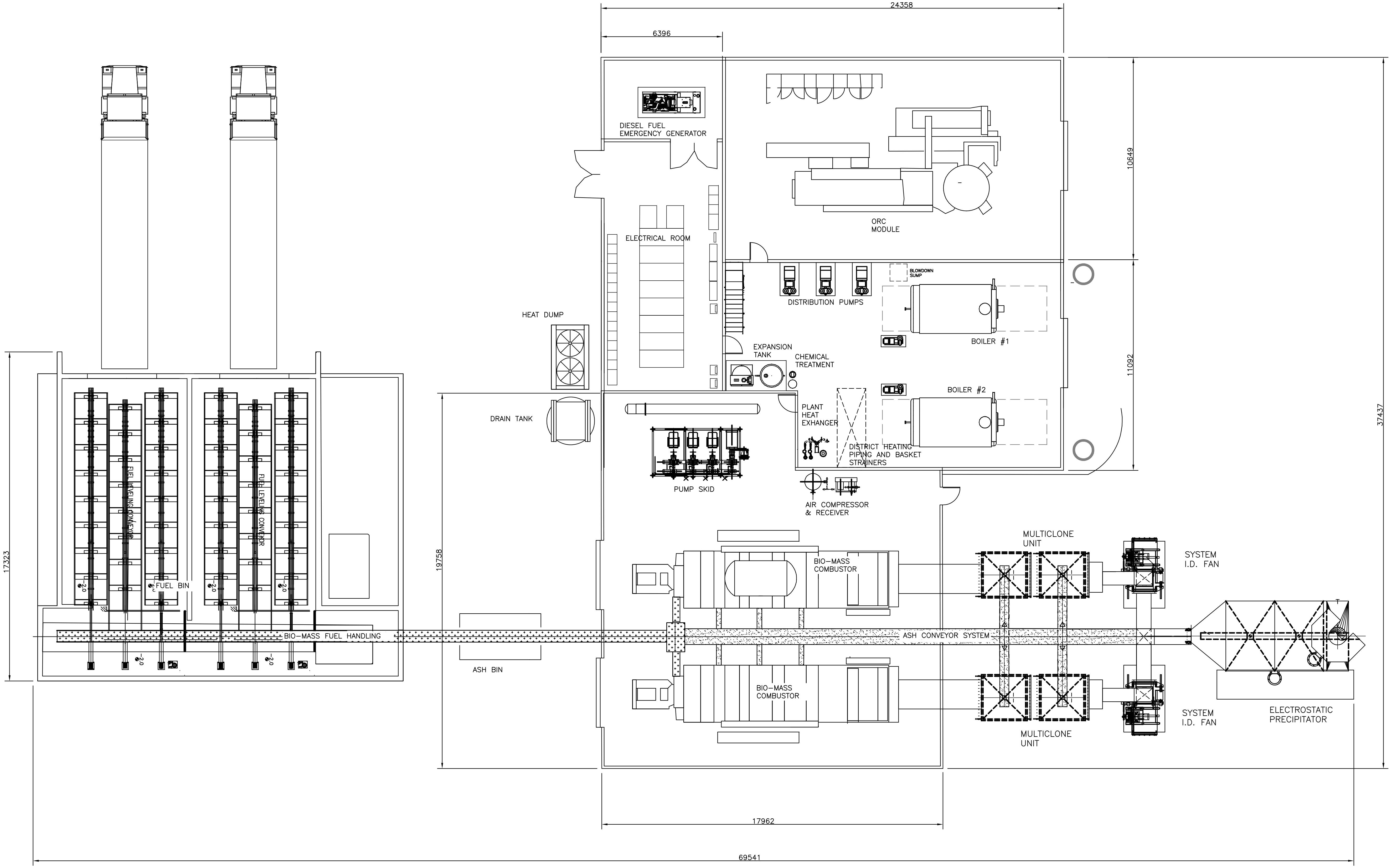
SHEET TITLE:
ENERGY CENTRE P-2
BIO-MASS HEAT RECOVERY
SCHEMATIC

DGN: J. CHIN	SCALE: N.T.S.
DWN: W. JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: SK-1313-003

NOTES:

1. FUEL OIL STORAGE SYSTEM IS ASSUMED TO BE EXISTING AND NOT SHOWN.
2. BIO-MASS SYSTEM INFORMATION COURTESY OF WELLONS CANADA CORP.



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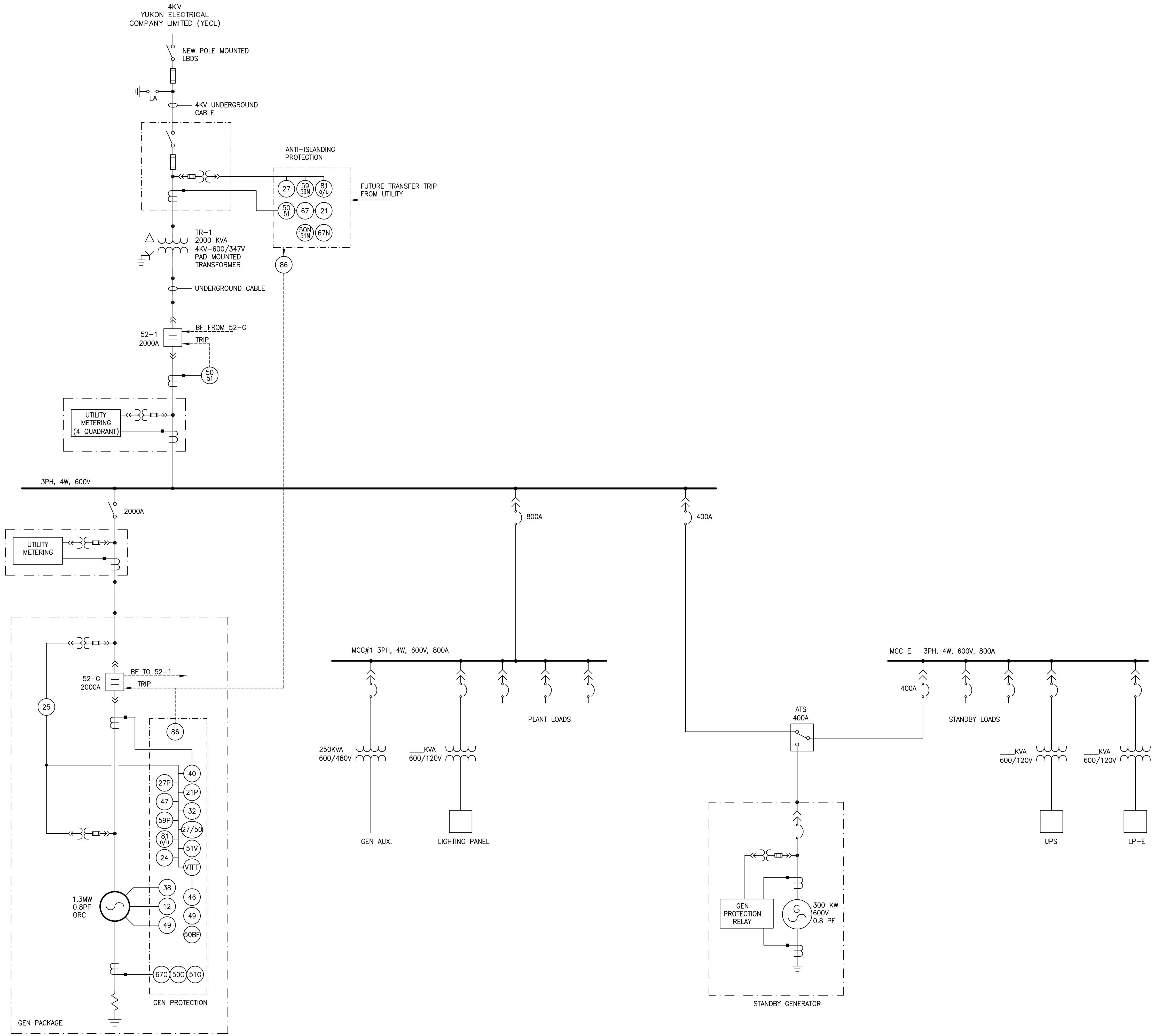
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-2
HEATING PLANT
PRELIMINARY EQUIPMENT LAYOUT

DGN: –	SCALE: N.T.S.
DWN: –	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012
DWG NO.: SK-1313-102	



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DATE	REMARKS	NO.

YUKON ENERGY

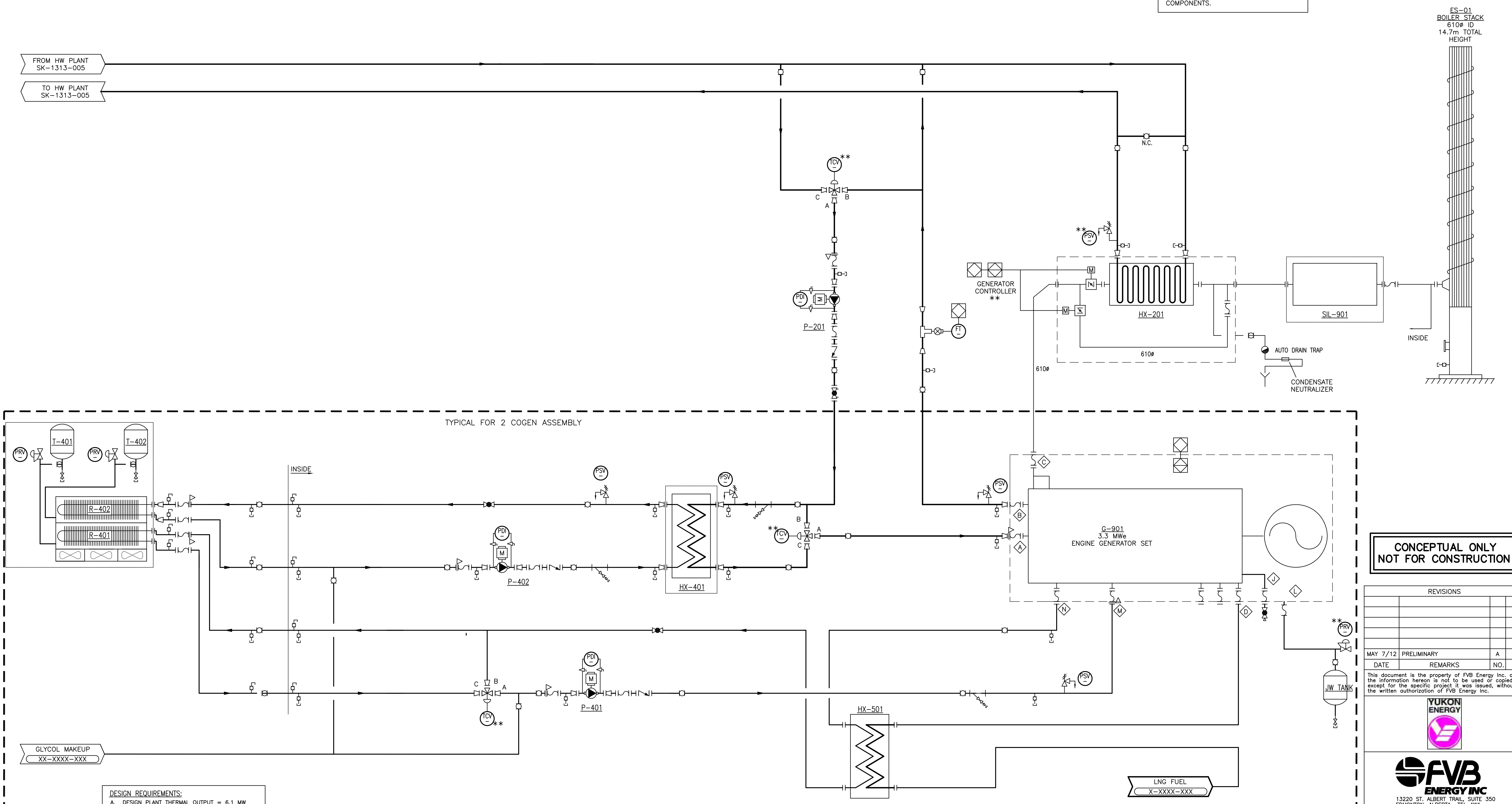
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
PLANT P-2
ELECTRICAL SINGLE LINE DIAGRAM
O.R.C. GENERATION OPTION

DGN:	SCALE: N.T.S.
DWN:	JOB NO.: 211313
APPR: _	DATE:
DWG NO.:	E-1313-002A

FIELD VERIFY EQUIPMENT CONNECTIONS PRIOR TO INSTALLING INTERCONNECTING PIPING, BREECHING AND ELECTRICAL COMPONENTS.



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

DESIGN REQUIREMENTS:

A. DESIGN PLANT THERMAL OUTPUT = 6.1 MW

B. THE DESIGN AND INSTALLATION OF THE PROCESS HW PIPING SHALL COMPLY WITH THE ASME CODE FOR POWER PIPING B31.1.

C. HYDROSTATIC TESTING WILL BE PERFORMED AT A PRESSURE OF 1.5 TIMES DESIGN PRESSURE.

D. THE HW PIPING WILL BE DESIGNED FOR WATER AT THE FOLLOWING CONDITIONS:
DESIGN PRESSURE: 1600 kPag (232 psi)
DESIGN TEMPERATURE: 120°C (248°F)
OVERPRESSURE PROTECTION AT: 1000 kPag

E. THE GLYCOL PIPING WILL BE DESIGNED FOR GLYCOL SOLUTION AT THE FOLLOWING CONDITIONS:
DESIGN PRESSURE: 1000 kPag
DESIGN TEMPERATURE: 99°C
OVERPRESSURE PROTECTION AT: 1000 kPag

G-901
ENGINE GENERATOR SET
OUTPUT: 3.3 MW ELECTRIC
MANUFACTURER:
MODEL:
OUTPUT:

P-101
HOT WATER DISTRIBUTION PUMPS
MANUFACTURER:
HEAD:
MOTOR:
SERIAL
MODEL:

P-201
ENGINE HEAT RECOVERY PUMP
MANUFACTURER:
FLOW:
HEAD:
MOTOR:
SERIAL
MODEL

P-401
R-401 CIRCULATION PUMP
FLOW:
HEAD:
MOTOR:
TYPE:

P-402
R-402 CIRCULATION PUMP
MANUFACTURER:
FLOW:
HEAD:
MOTOR:
SERIAL
MODEL

T-401
RAD EXPANSION TANK

T-402
RAD EXPANSION TANK

R-401
LOW TEMPERATURE RADIATOR INTERCOOLER 2nd STAGE

R-402
HIGH TEMPERATURE RADIATOR INTERCOOLER 1st STAGE

SIL-901
EXHAUST GAS SILENCER

HX-201
EXHAUST GAS HEAT RECOVERY
DUTY:

HX-401
PLATE HEAT EXCHANGER
DUTY:

HX-501
PLATE HEAT EXCHANGER
DUTY: LNG PREHEAT

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MAY 7/12	PRELIMINARY	A

YUKON ENERGY

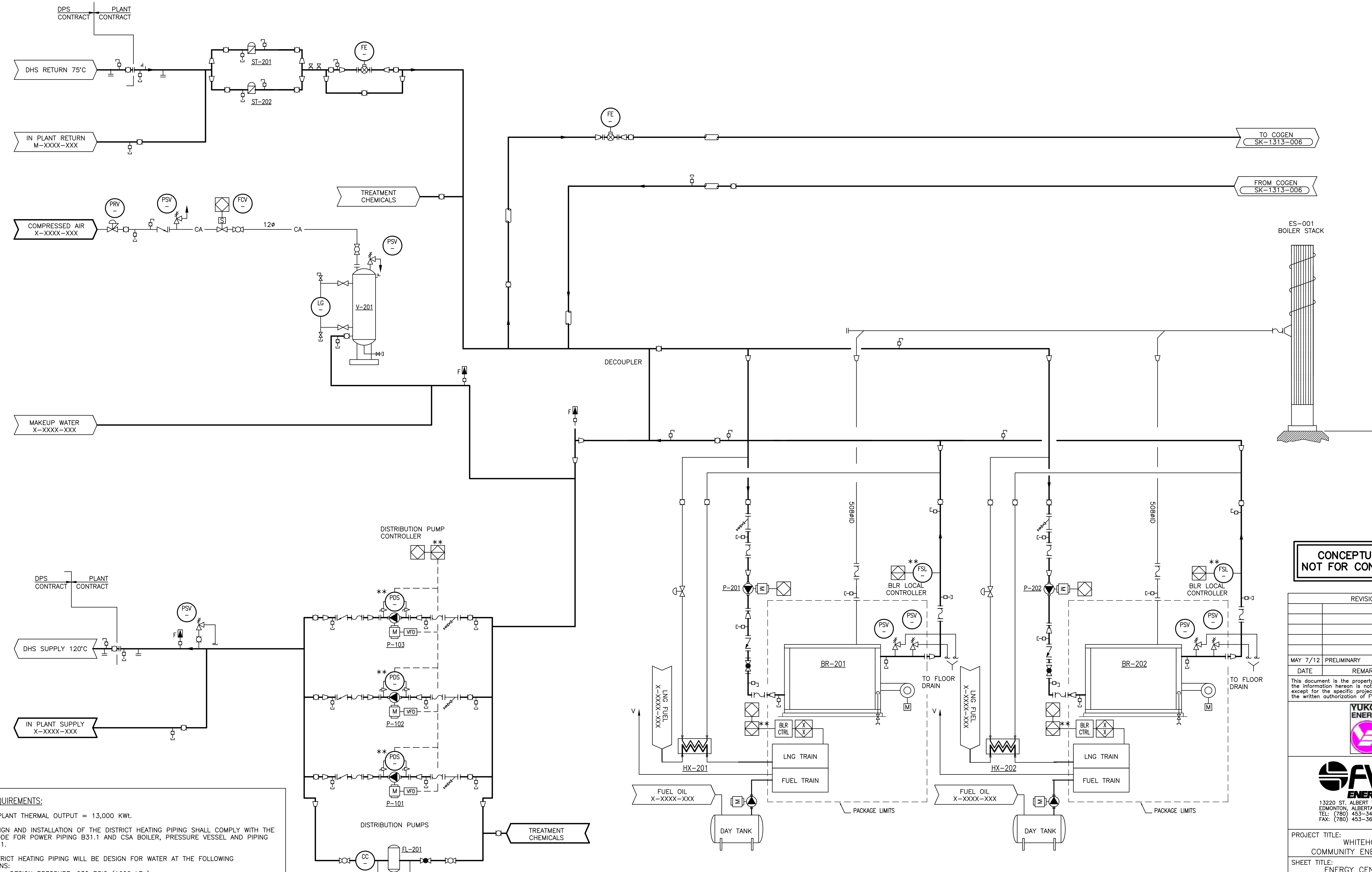
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-2
HEATING PLANT SCHEMATIC
LNG COGEN CONCEPT

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: AUG 01/2012

DWG NO.: SK-1313-006



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

DESIGN REQUIREMENTS:

1. DESIGN PLANT THERMAL OUTPUT = 13,000 KWt.
2. THE DESIGN AND INSTALLATION OF THE DISTRICT HEATING PIPING SHALL COMPLY WITH THE ASME CODE FOR POWER PIPING B31.1 AND CSA BOILER, PRESSURE VESSEL AND PIPING CODE B51.
3. THE DISTRICT HEATING PIPING WILL BE DESIGN FOR WATER AT THE FOLLOWING CONDITIONS:
   DESIGN PRESSURE: 232 PSIG (1600 kPa)
   DESIGN TEMPERATURE: 248 F (120 C)
   OPERATING TEMPERATURE: 243 F (117 C)
4. HYDROSTATIC TESTING WILL BE PERFORMED AT A PRESSURE OF 1.5 TIMES DESIGN.
5. OVERPRESSURE PROTECTION WILL BE PROVIDED AT EACH BOILER; RELIEF VALVE SETTING=160 PSIG (1103 kPa).

P-101/102/103
DISTRIBUTION CENTRIFUGAL PUMPS
FLOW: XX.X L/s (each)
HEAD: XX.X m
MOTOR: XX kW
SUPPLIED BY:

BR-201/202
HW BOILER
DUTY: 4.0 MW (408 BHP)
SUPPLIED BY:

FL-201
SIDESTREAM FILTER

HX-201/202
LNG PREHEAT PLATE HEAT EXCHANGER

P-201/202
BOILER CIRCULATION PUMP
FLOW: XX L/s
HEAD: XX.X m
MOTOR: X.X kW

V-201
EXPANSION TANK
TANK VOL: XXX L
DESIGN PRESSURE: XXX kPag & XXX°C

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MAY 7/12	PRELIMINARY	A
DATE	REMARKS	NO.

YUKON ENERGY

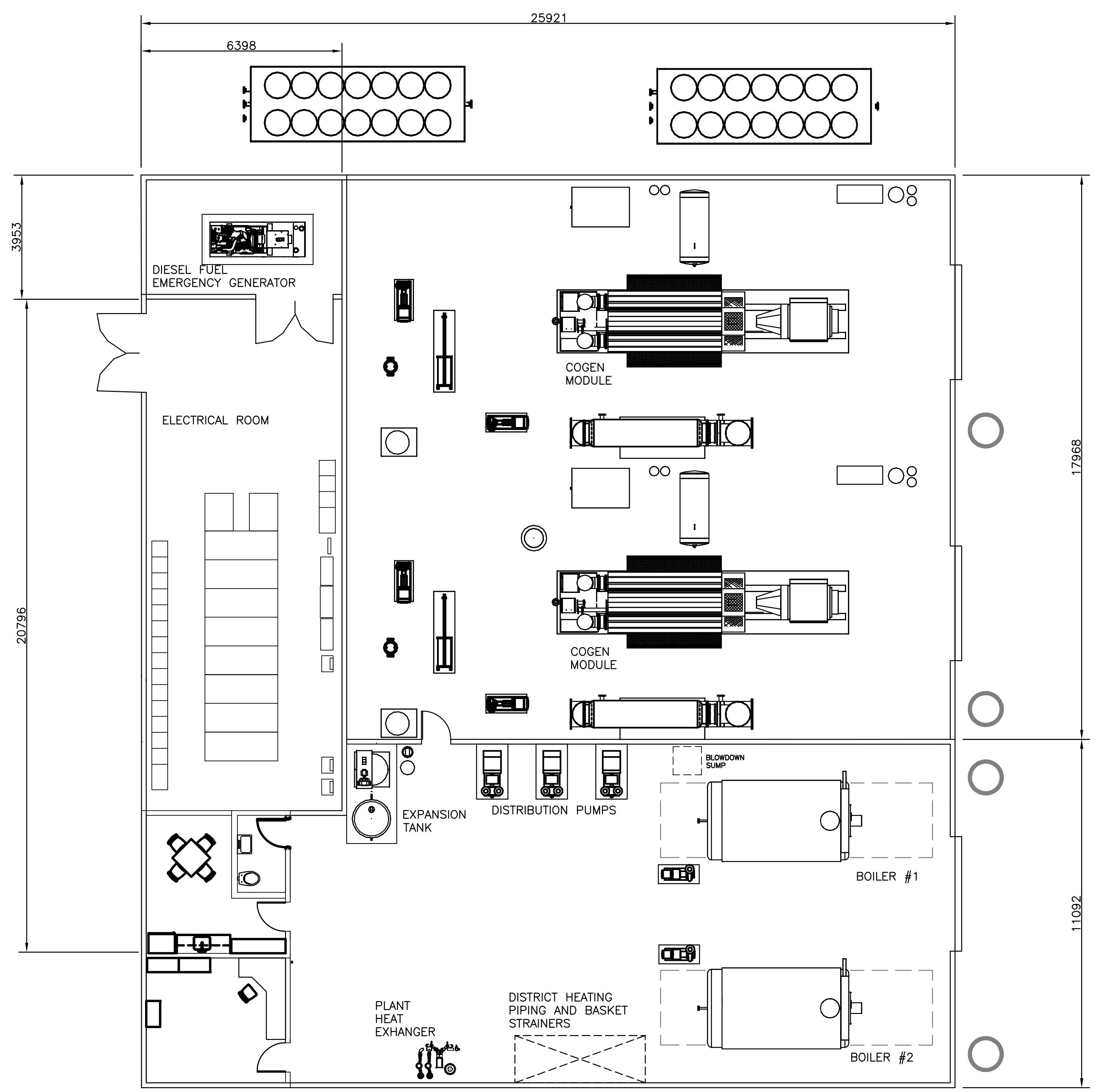
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-2
HEATING PLANT SCHEMATIC
LNG BOILER CONCEPT

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: AUG 01/2012

DWG NO.: SK-1313-005



CONCEPTUAL DESIGN

REVISIONS		
DATE	REMARKS	NO.

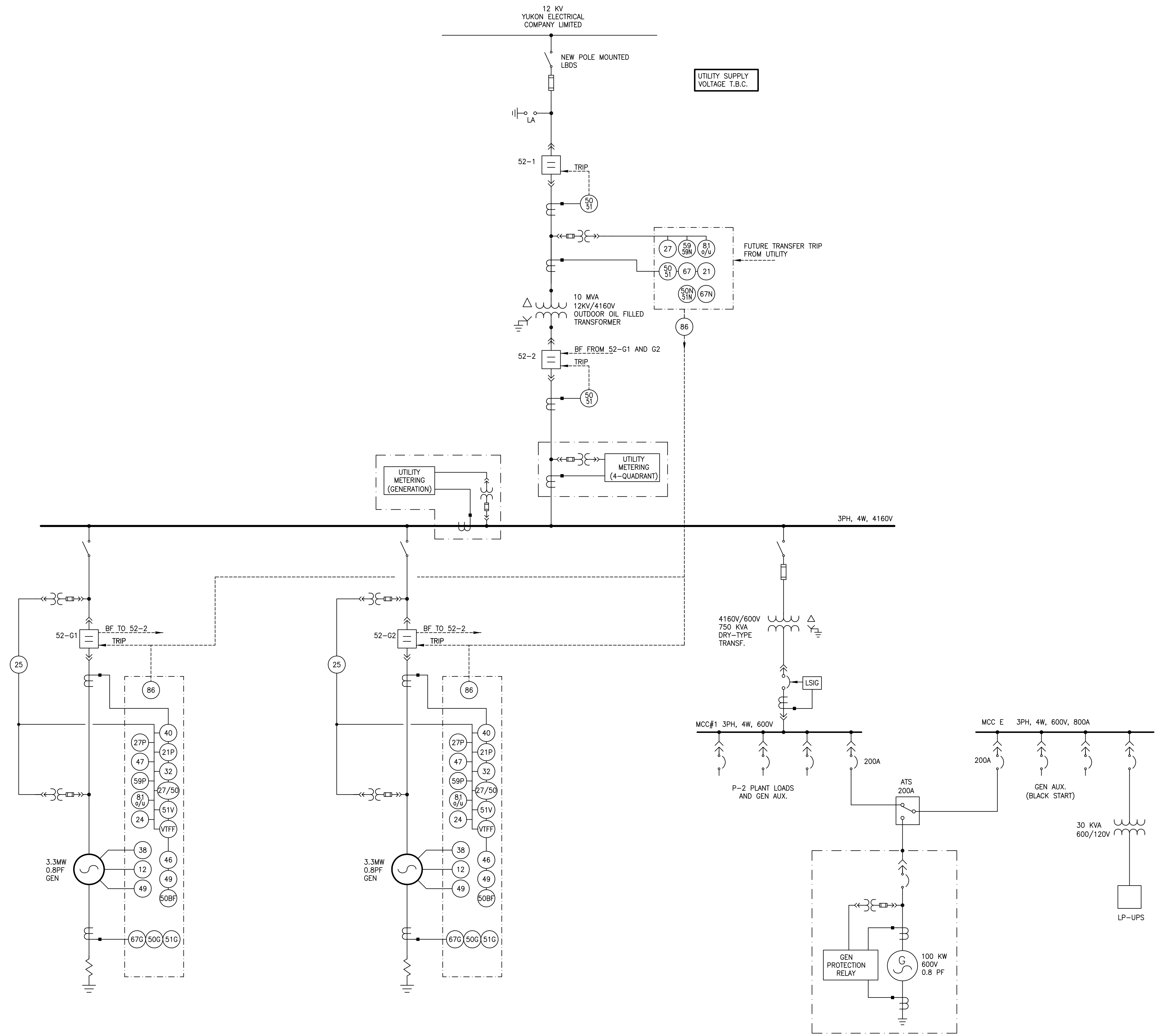
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P-2
HEATING PLANT c/w COGEN
PRELIMINARY EQUIPMENT LAYOUT

DGN: –	SCALE: N.T.S.
DWN: –	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012
DWG NO.: SK-1313-104	



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

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DATE	REMARKS	NO.	

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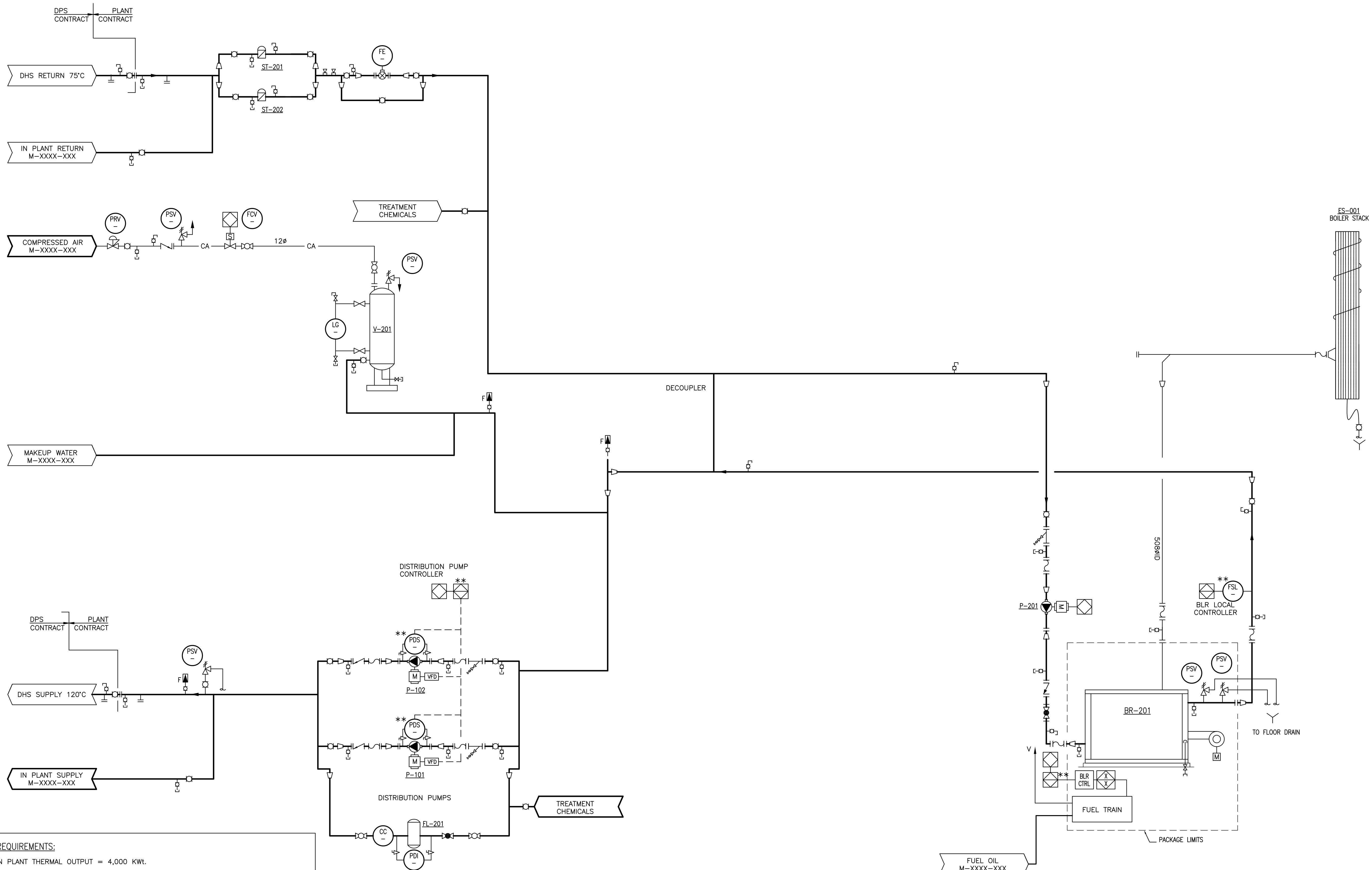
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
PLANT P-2
ELECTRICAL SINGLE LINE DIAGRAM
ORC OPTION

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: E-1313-002



CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

DESIGN REQUIREMENTS:

1. DESIGN PLANT THERMAL OUTPUT = 4,000 KWt.
2. THE DESIGN AND INSTALLATION OF THE DISTRICT HEATING PIPING SHALL COMPLY WITH THE ASME CODE FOR POWER PIPING B31.1 AND CSA BOILER, PRESSURE VESSEL AND PIPING CODE B51.
3. THE DISTRICT HEATING PIPING WILL BE DESIGN FOR WATER AT THE FOLLOWING CONDITIONS:
   DESIGN PRESSURE: 232 PSIG (1600 kPa)
   DESIGN TEMPERATURE: 248 F (120 C)
   OPERATING TEMPERATURE: 243 F (117 C)
4. HYDROSTATIC TESTING WILL BE PERFORMED AT A PRESSURE OF 1.5 TIMES DESIGN.
5. OVERPRESSURE PROTECTION WILL BE PROVIDED AT EACH BOILER; RELIEF VALVE SETTING=160 PSIG (1103 kPa).

BR–201
HW BOILER
DUTY: 4.0 MW (408 BHP)
SUPPLIED BY:

P–101/102
DISTRIBUTION CENTRIFUGAL PUMPS
FLOW: XX.X L/s (each)
HEAD: XX.X m
MOTOR: XX kW
SUPPLIED BY:

P–201
BOILER CIRCULATION PUMP
FLOW: XX L/s
HEAD: XX.X m
MOTOR: X.X kW

V–201
EXPANSION TANK
TANK VOL: XXX L
DESIGN PRESSURE: XXX kPag & XXX°C

FL–201
SIDESTREAM FILTER

REVISIONS

DATE	REMARKS	NO.
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YUKON ENERGY

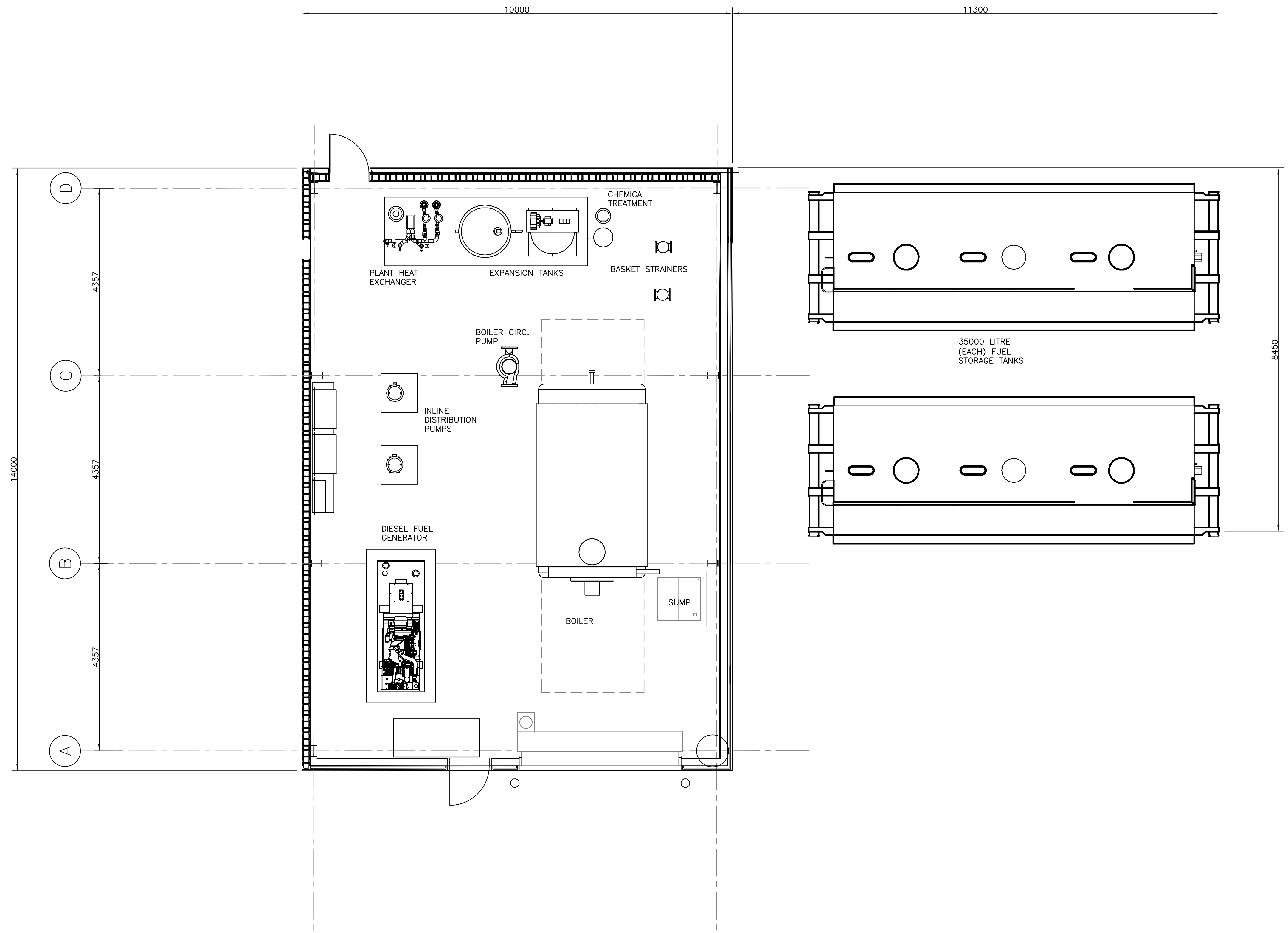
FVB ENERGY INC

13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
ENERGY CENTRE P–3
HEATING PLANT SCHEMATIC

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012
DWG NO.: SK–1313–004	



CONCEPTUAL DESIGN

REVISIONS		
DATE	REMARKS	NO.

YUKON ENERGY

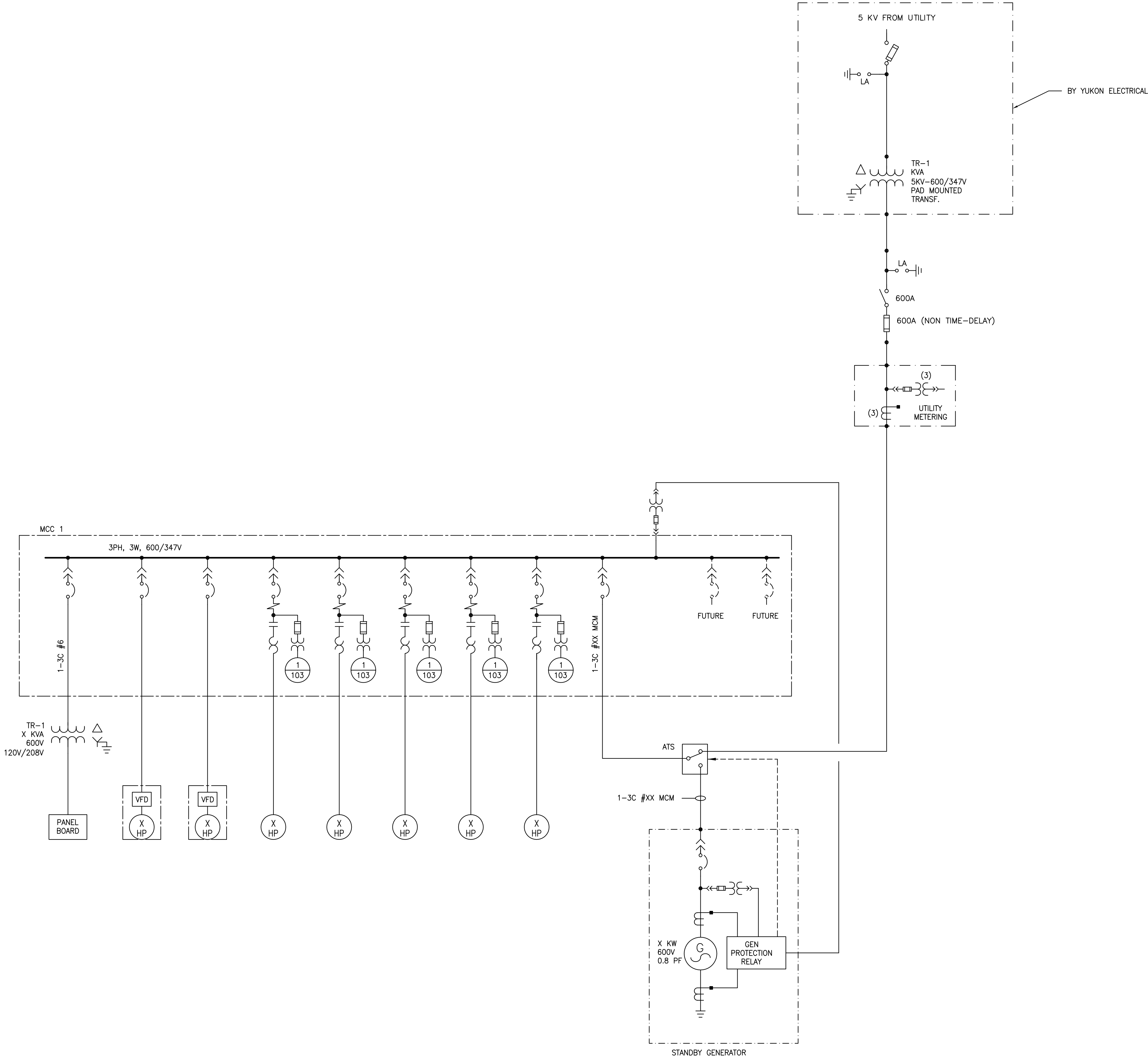
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE

SHEET TITLE: ENERGY CENTRE P-3 DOWNTOWN ENERGY PLANT PRELIMINARY LAYOUT

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012

DWG NO.: SK-1313-103



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YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE
COMMUNITY ENERGY SYSTEM

SHEET TITLE:
PLANT P-3
ELECTRICAL SINGLE LINE DIAGRAM

DGN: J.CHIN	SCALE: N.T.S.
DWN: W.JENSEN	JOB NO.: 211313
APPR: _	DATE: MAY 01/2012
DWG NO.: E-1313-003	

Appendix II - Distribution Piping System Drawing Package

1.0 OVERALL PLAN
1:10000

0 500 200 400 1000
SCALE 1:10000

LEGEND:

PHASE 1

P1. Hospital Spare

1. Whitehorse General Hospital
2. Thomson Centre
5. #1 Hospital Road – Crocus Ridge
6. Education Building
1A. F.H. Collins Secondary School
2A. Selkirk Elementary School

PHASE 2

P2. Alternative Energy

7. Christ the King Elementary School
21. YEC Office
22. YEC Diesel Plant
23. YEC P125 Hydro Generating Facility

PHASE 3

P3. Downtown Energy Centre

1. Yukon Territory Government Admin Bldg
2. Whitehorse Visitor Information Centre
3. Closeleigh Manor
4. Edgewater Hotel
5. Horwood's Shopping Plaza
6. City Hall / Fire Hall
7. Canada's Best Value Inn
10. Pro Log Project Logistics
11. Financial Plaza
16. Law Courts (Yukon Justice Building)
17. 202 Motor Inn
21. High Country Inn

PHASE 4

15. Westmark Hotel & Conf. Centre
22. 3090 Lambert St.
25. Elijah Smith
26. Lynn Building
27. Prospector Place
28. Residential at Strickland st. and 4th ave
29. Whitehorse Elementary School
39. RCMP Building (to be renovated in future)
40. Town & Mountain Hotel
41. Best Western Gold Rush Inn
42. RBC Royal Bank
44. Wood Street Centre
45. Stratford Motel

PHASE 5

6. Vanier Catholic Secondary School
9. The Pine (31 Lewes)
11. Skyline Apartments
12. 93 Lewes Blvd (Block B)
13. 93 Lewes Blvd (Block A)
14. 1 Klondike Road
15. Norman D. Macaulay Lodge
20. Peak Commercial

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DATE	REMARKS	NO.

CLIENT: YUKON ENERGY

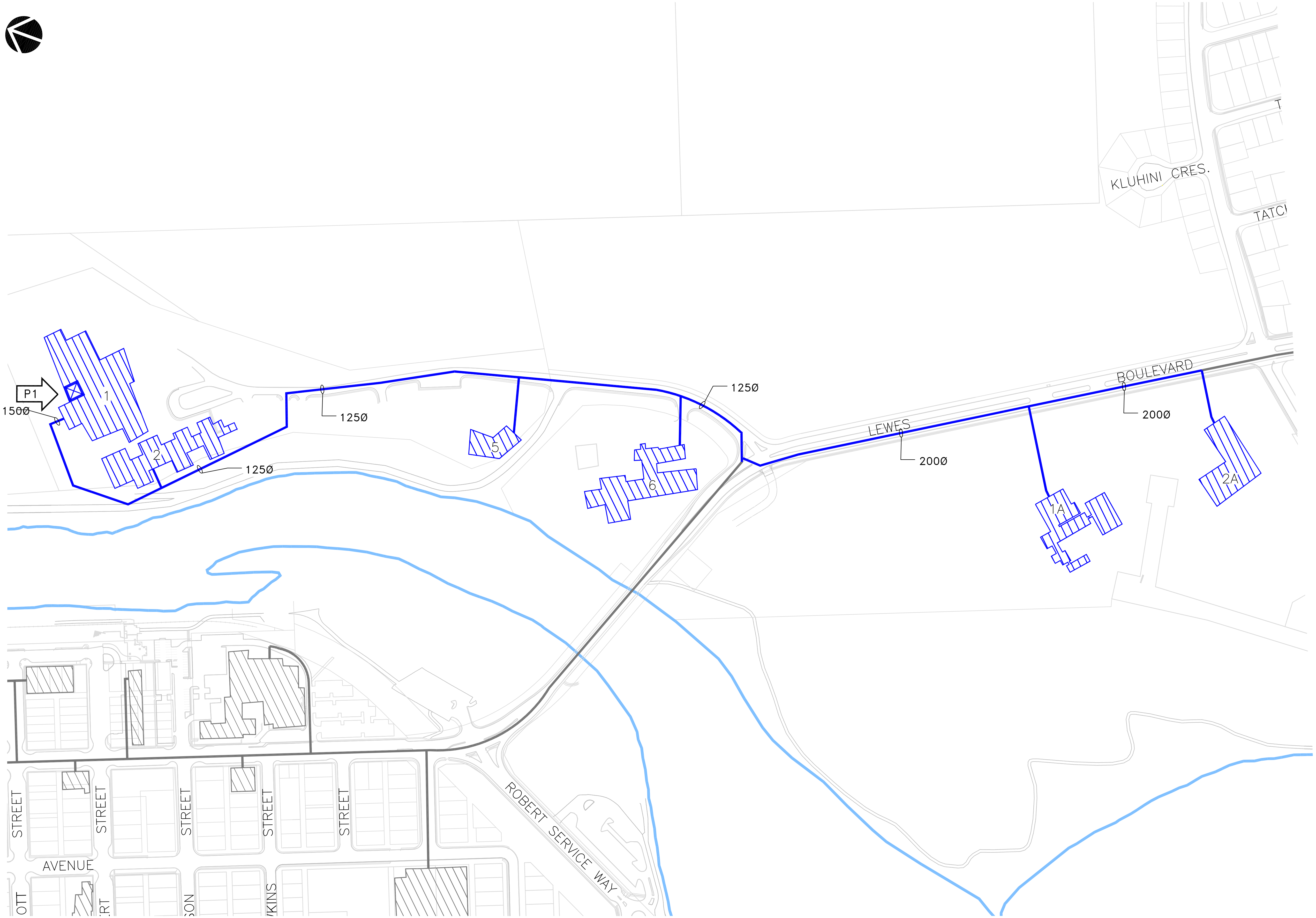
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PIPE ROUTING AND PHASING OVERALL LAYOUT

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012

DWG NO.: PD-1313-001



1.0 **OVERALL PLAN**
1:10000

0 10 40 80 200
SCALE 1:4000

LEGEND:

PHASE 1

P1. Hospital Spare

1. Whitehorse General Hospital
2. Thomson Centre
5. #1 Hospital Road – Crocus Ridge
6. Education Building
1A. F.H. Collins Secondary School
2A. Selkirk Elementary School

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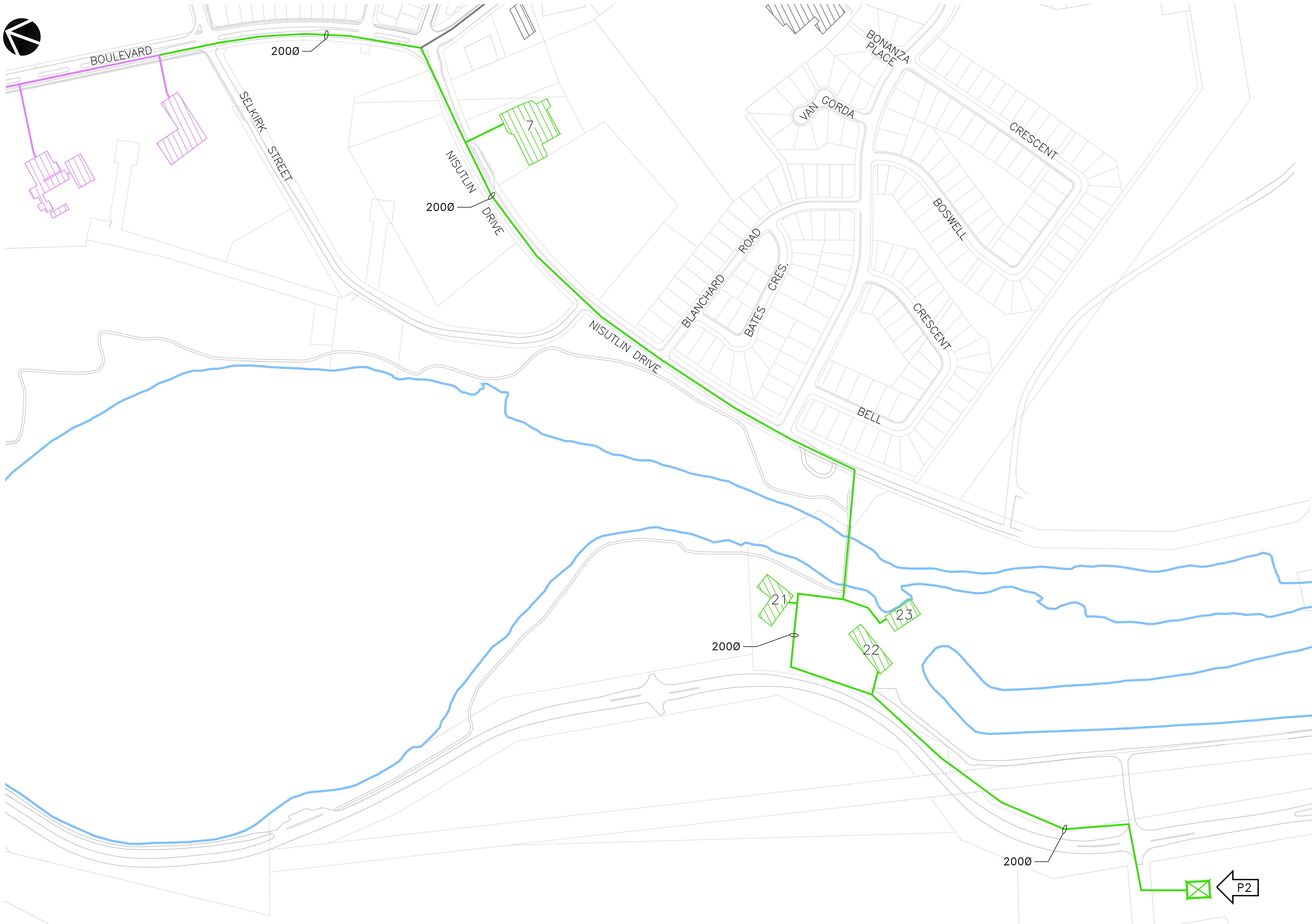
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PHASE 1

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012

DWG NO.: PD-1313-002



1.0
1:10000
OVERALL PLAN

LEGEND:

PHASE 2

P2. Alternative Energy
7. Christ the King Elementary School
21. YEC Office
22. YEC Diesel Plant
23. YEC P125 Hydro Generating Facility

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CLIENT: YUKON ENERGY

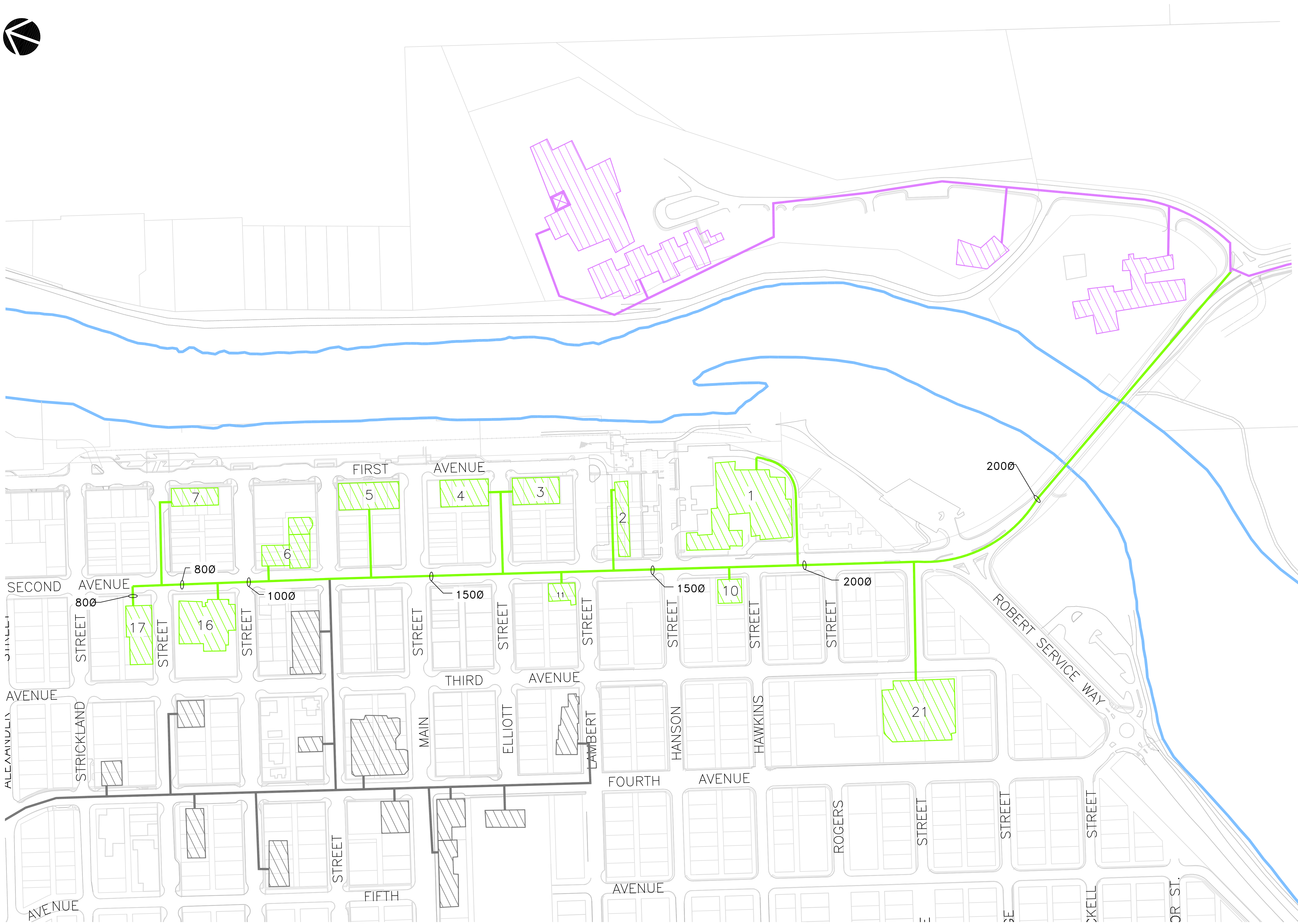
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PHASE 2

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012

DWG NO.: PD-1313-003



LEGEND:

PHASE 3

1. Yukon Territory Government Admin Bldg
2. Whitehorse Visitor Information Centre
3. Closeleigh Manor
4. Edgewater Hotel
5. Horwood's Shopping Plaza
6. City Hall / Fire Hall
7. Canada's Best Value Inn
10. Pro Log Project Logistics
11. Financial Plaza
16. Law Courts (Yukon Justice Building)
17. 202 Motor Inn
21. High Country Inn

1.0 OVERALL PLAN
1:10000

0 10 40 80 200
SCALE 1:4000

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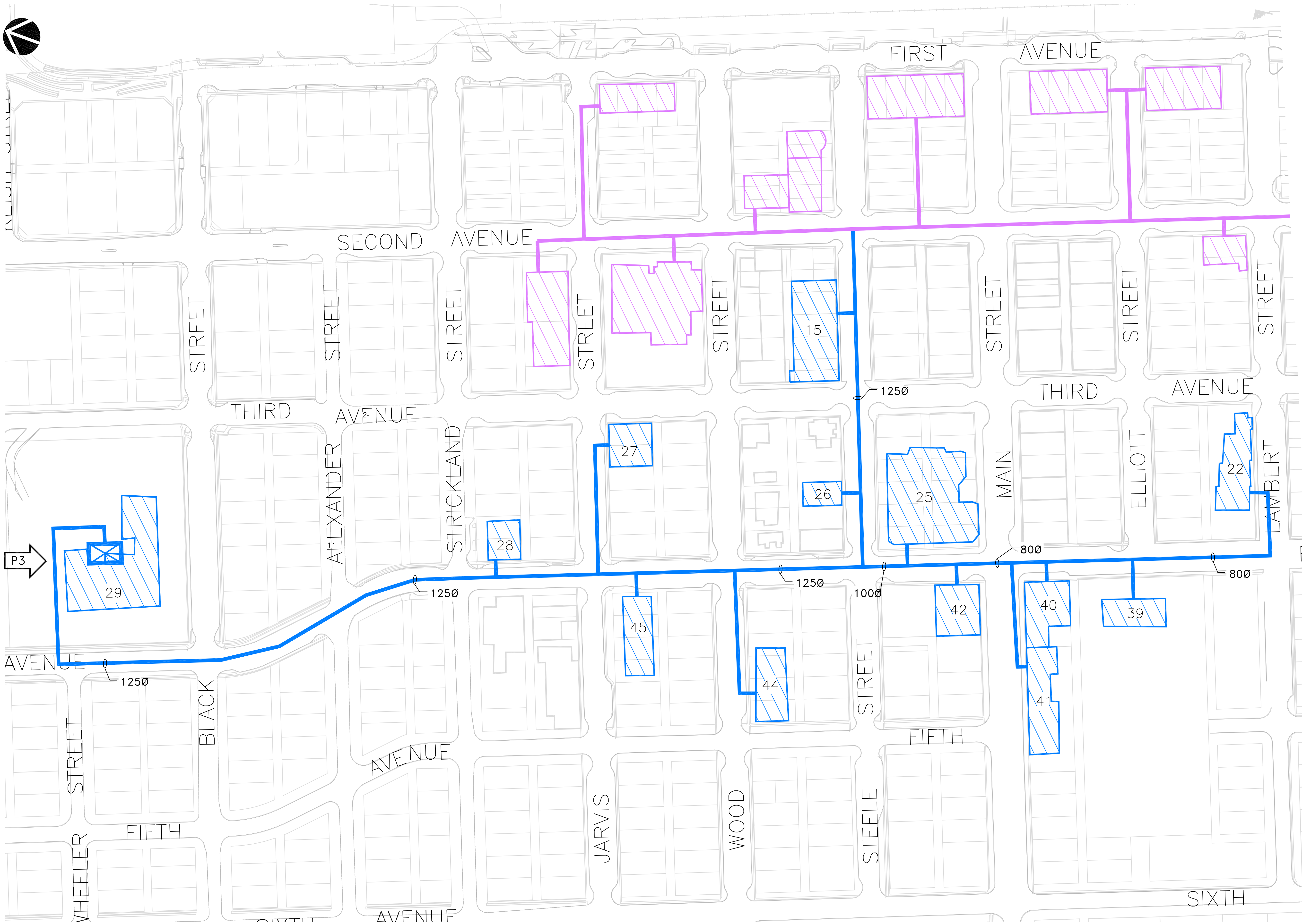
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PHASE 3

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012
DWG NO.: PD-1313-004	



LEGEND:

PHASE 4

15. Westmark Hotel & Conf. Centre
22. 3090 Lambert St.
25. Elijah Smith
26. Lynn Building
27. Prospector Place
28. Residential at Strickland st. and 4th ave
29. Whitehorse Elementary School
39. RCMP Building (to be renovated in future)
40. Town & Mountain Hotel
41. Best Western Gold Rush Inn
42. RBC Royal Bank
44. Wood Street Centre
45. Stratford Motel

1.0 OVERALL PLAN 1:10000

0 25 50 125

SCALE 1:2500

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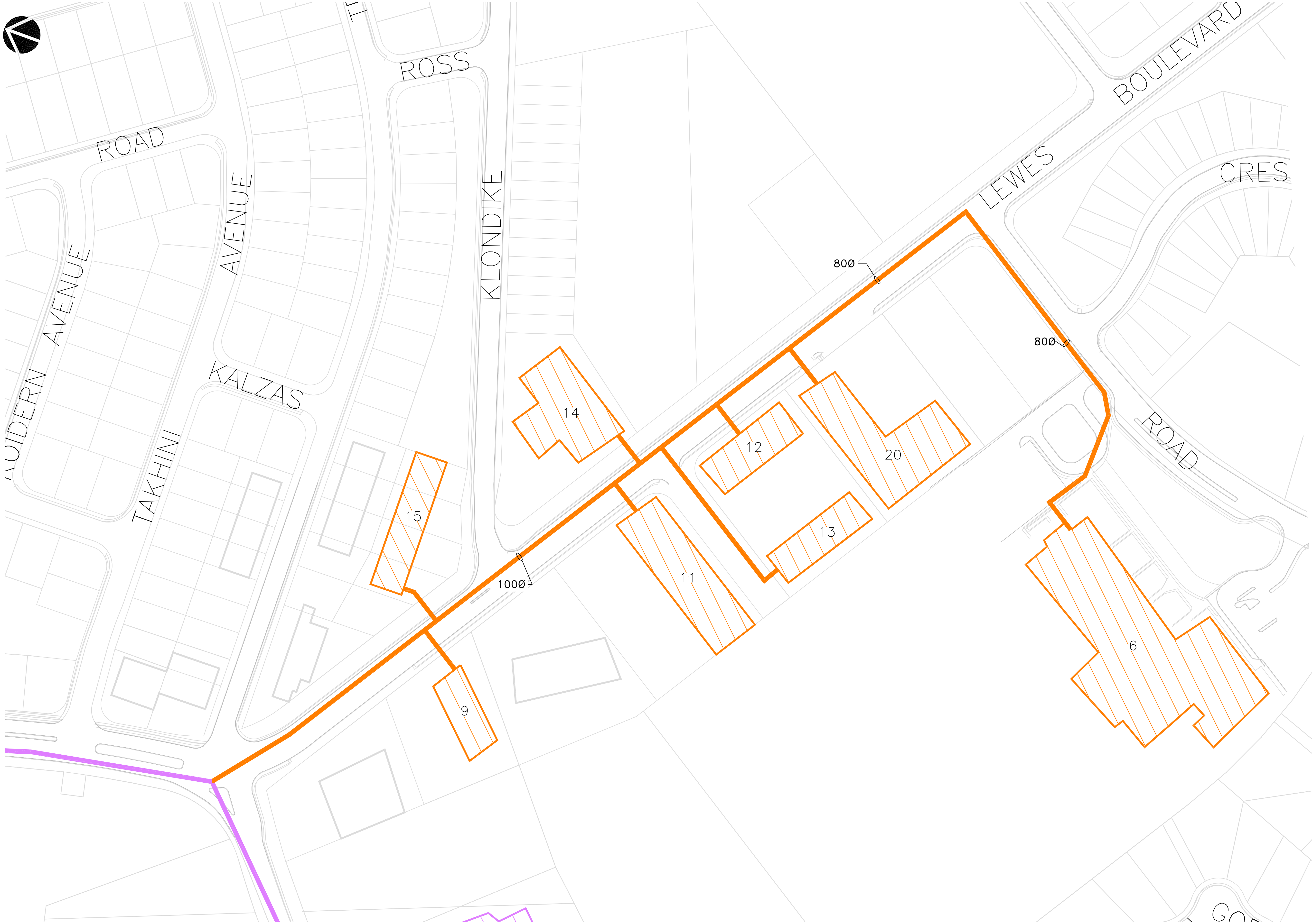
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PHASE 4

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012
DWG NO.: PD-1313-005	



LEGEND:

PHASE 5

6. Vanier Catholic Secondary School
9. The Pine (31 Lewes)
11. Skyline Apartments
12. 93 Lewes Blvd (Block B)
13. 93 Lewes Blvd (Block A)
14. 1 Klondike Road
15. Norman D. Macaulay Lodge
20. Peak Commercial

1.0 OVERALL PLAN 1:10000

0 5 20 40 100
SCALE 1:2000

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CLIENT: YUKON ENERGY

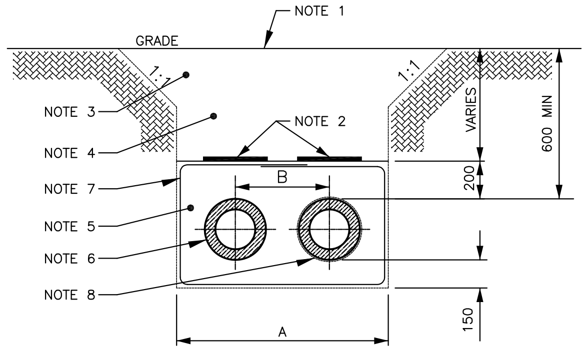
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE: DISTRIBUTION PIPING SYSTEM PHASE 5

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012

DWG NO.: PD-1313-006



1 TYPICAL TRENCH CROSS-SECTION PARALLEL DISTRICT HEATING PIPES
NTS

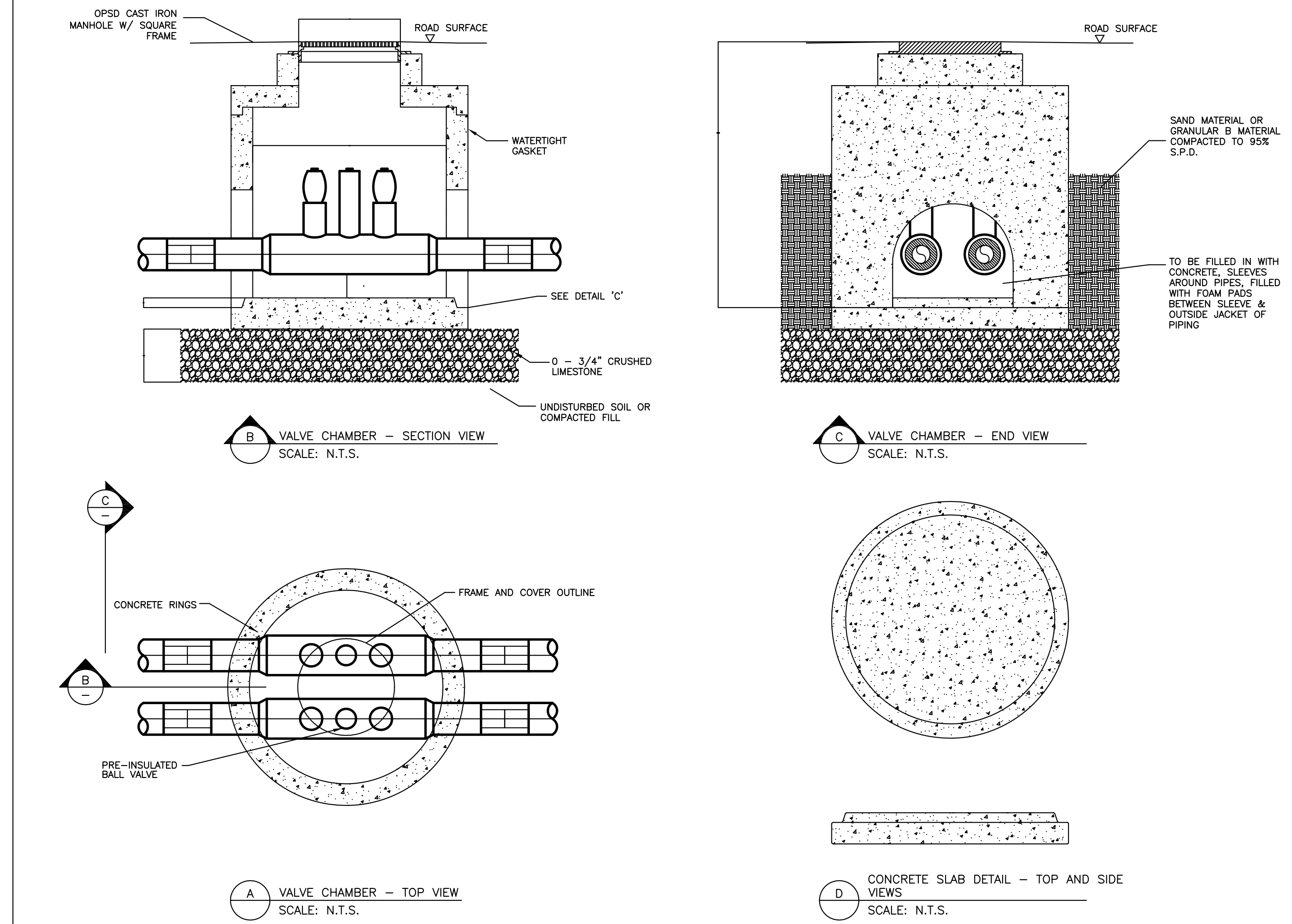
TYPICAL PARALLEL TRENCH DIMENSIONS
(RECOMMENDED MINIMUMS)

PIPE SIZE(mm)	NPS(mm)	NPS(in)	A(mm)	B(mm)	A(ft–in)	B(ft–in)
48.3/110	40ø	1 1/2"	800	300	2'–8"	1'–0"
60.3/125	50ø	2"	825	325	2'–9"	1'–1"
76.1/140	65ø	2 1/2"	850	325	2'–10"	1'–1"
88.9/160	80ø	3"	900	350	3'–0"	1'–2"
114.3/200	100ø	4"	975	400	3'–3"	1'–4"
139.7/225	125ø	5"	1025	425	3'–5"	1'–5"
168.3/250	150ø	6"	1075	450	3'–7"	1'–6"
219.1/315	200ø	8"	1200	500	4'–0"	1'–8"

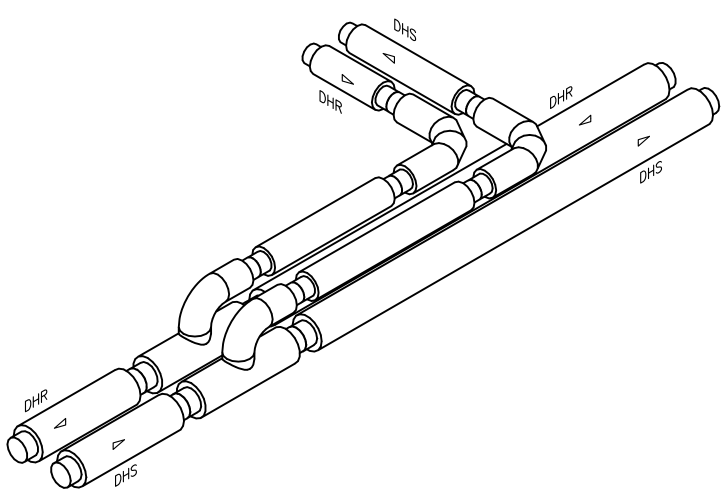
NOTE: 114.3/200 – REFERS TO: OD OF PIPE / OD OF INSULATION JACKET

TRENCH NOTES:

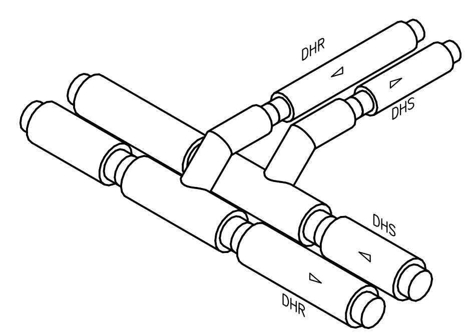
1. –ALL RE–INSTATEMENT TO MEET SPECIFICATION OR LOCAL AUTHORITY REQUIREMENTS.
   –RE–INSTATE GRADE TO MATCH EXISTING CONDITIONS.
   –ASPHALTIC CONCRETE SURFACES PROVIDE STRAIGHT SAW CUT EDGE, 300mm MIN. OUTSIDE EXCAVATED AREA.
2. WARNING TAPE ABOVE ALL PIPE.
3. TRENCH SIDE SLOPES TO LOCAL OR PROVINCIAL REGULATORY AGENCY.
4. APPROVED SELECTED BACKFILL MATERIAL FROM EXCAVATION OR OTHER SOURCES.
5. APPROVED SAND BEDDING AND SURROUND COMPACTED TO 95% AS PER SPEC.
6. PRE–INSULATED DISTRICT HEATING PIPES.
7. GEOTEXTILE TO WRAPPED AROUND SAND BEDDING.



2 VALVE CHAMBER WITH VENT/ISOLATION VALVE CONNECTIONS - TYPICAL MANHOLE -
NTS



3 TYPICAL PARALLEL BRANCH
NTS



4 TYPICAL 45° BRANCH
NTS

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YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY ENERGY SYSTEM

SHEET TITLE:
DISTRIBUTION PIPING SYSTEM TYPICAL DETAILS

DGN: C. HERBERS	SCALE: AS SHOWN
DWN: V. DION	JOB NO.: 211313
APPR: R. DOYLE	DATE: MAR 06/2012

DWG NO.: PD–1313–007

Appendix III – Energy Transfer Station Drawing Package

III.i Existing Building Descriptions

Twelve buildings were selected for the development of preliminary connection schematics to the proposed community heating system.

1. Whitehorse General Hospital

The Whitehorse General Hospital has 49 beds and 10 surgical day beds and is the primary health care facility for the Yukon. The facility has a cafeteria and laundry facility on site. It is heated by three low pressure steam boilers located in the Energy Centre. Low pressure steam is provided to two steam to glycol shell & tube heat exchangers for heating of the air handling unit coils. There are five air handling units located in the penthouse for providing ventilation (one is redundant). There is also a heat recovery wheel that runs when it is cold outside. Low pressure steam is provided to two steam to hot water shell & tube heat exchangers for heating of the radiant panels, miscellaneous radiators, and VAV duct heaters (for space heating). Low pressure steam is provided to steam coils in two high temperature domestic hot water tanks and two low temperature domestic hot water tanks. Low pressure steam also currently runs to the air handling units to meet the humidification demands.

The Whitehorse General Hospital has two high pressure steam boilers that serve the three sterilizers (one is redundant) in the facility. These units will not be displaced by the community heating system.

2. Thomson Centre

The Thomson Centre is right next to the General Hospital and has space for 29 beds. The facility provides therapy services and extended care space for the region. It has steam converters located in the basement that are fed from the main Hospital Energy Centre low pressure steam system. There is one steam to glycol shell & tube heat exchanger for the air handling system heating and one steam to hot water shell & tube heat exchangers for heating of radiant panels. There are also two steam to hot water shell & tube heat exchangers for domestic hot water heating with two large tanks for storage.

3. Education Building

The Education Building was the original college back in the 1960’s. There are one to two floors above grade. The building now operates primarily as an office building for the Yukon Education department. It has eight small propane-fired hot water boilers in the ground floor mechanical room. The air handling unit coils are heated from a glycol loop (the air handling units and glycol heat exchanger are located in the penthouse mechanical room). The main radiant panels and baseboard units are fed off of the hot water loop. A 65 gallon electrical domestic hot water tank serves the hot water load for the building.

4. Yukon Territory Government Administration Building

The Main Administration Building is primarily an office building from 1974 (the library portion has been closed) and has four oil-fired hot water boilers in the penthouse (4^{th} floor) mechanical room providing heat to the building. One of the boilers is considerably smaller for summer and shoulder season operation. The humidification boiler is not used. The air handling coils for the fan rooms operate off of a glycol loop (the heat exchanger to glycol is not located in the mechanical room). This building has a heating control system. There are thermostats that control the different zones. A large domestic hot water storage tank is heated by a heat exchanger off the main heating loop. This building has a kitchen and cafeteria.

5. City Hall / Fire Hall

The City Hall and Fire Hall are heated by 3 oil-fired hot water boilers in the ground floor mechanical room in the Fire Hall. Heating pipes through a tunnel connect the two building mechanical rooms together. The Fire Hall has radiant and unit heaters. The City Hall has two different systems due to two separate construction periods. Radiant panels are used in the newer part and the old section is heated only by air with some perimeter radiant heating. One electric domestic hot water tank is located in the Fire Hall mezzanine and another is located in the new part of the City Hall. The air handling unit coils are heated from the glycol loop.

6. High Country Inn & Convention Centre

The High Country Inn & Convention Centre is a four storey hotel with 83 suites, a restaurant and convention centre (separate building) originally built in the 1970's. The heating system has recently been upgraded with condensing boilers installed in 2010a and a boiler control system. There is a main mechanical room housing the new boilers, domestic hot water tanks, and pumps in the hotel on the ground floor. Piping connects to the Convection Centre boiler room and currently runs through the boiler and then to the building heating system. Radiators are located in each suite. There is one air handling unit on the roof for ventilation of the convention centre and hotel space and it is heated from the glycol loop. There are three new domestic hot water tanks that are heated with boiler coils from the main heating loop.

7. Yukon Energy Office (Information from the Stantec Energy Audit)

The Yukon Energy office is a three-storey building built in 1998. The first two floors are general office space and the top floor is the Service Control Centre, which operates 24 hours a day and houses primarily servers for the control of the electrical generation system. The top floor needs cooling all year round (and very little heating). An electric boiler primarily heats the building, with two oil-fired boilers as back-up. The mechanical room is located on the ground floor. Fan coil units connected to the hot water loop provide space heating throughout the offices and a cabinet heater is located in the main entrance. The building has an automation system. One make-up air handling unit with a hot water heating coil provides ventilation for the building. Two electric domestic hot water tanks provide hot water for the building.

8. Yukon Energy P125 Hydro Generating Facility

The Yukon Energy P125 Hydro Generating facility was constructed in 1958, but it underwent major renovation after a fire in 1997. It is a three storey structure that provides access to three hydro turbines. The building is heated by an electric hot water boiler with an oil-fired back-up located on the main floor. Hot water is distributed to multiple unit heaters to heat the space. One make-up air handling unit is located on the main level to provide cooling and ventilation. There is also a make-up air unit located outside. Exhaust fans provide ventilation to the turbine level as well. The domestic hot water load is very small as there is only one washroom. Manual thermostats control the building heating.

9. Law Courts (Yukon Justice Building)

The Law Courts building was built in 1962. It has 4 floors and a heated parkade below. The main boilers are located on the second floor and are oil-fired. A third smaller electric boiler is located in the parkade for summer and shoulder season use. There are three very large heating water storage tanks located in the parkade and heated off the hot water loop via a shell and tube horizontal heat exchanger. Solar panels are located on the roof to supply supplemental heating. There are three fan rooms for ventilation and these have hot water heating coils. Domestic hot water is served by a large tank with a boiler water coil and a small electric heater for summer use.

10. Whitehorse Elementary School

Whitehorse Elementary School is from the 1950's. It has three floors and houses the boiler equipment in the mechanical room on the ground floor. Two oil-fired boilers provide hot water to the radiant baseboards and unit heaters. A glycol loop serves the perimeter radiators and two air handling units for ventilation of the gymnasium and corridors. There are also four direct fired propane rooftop air handling units to ventilate the rest of the school space. Domestic hot water is served by two large oil fired tanks.

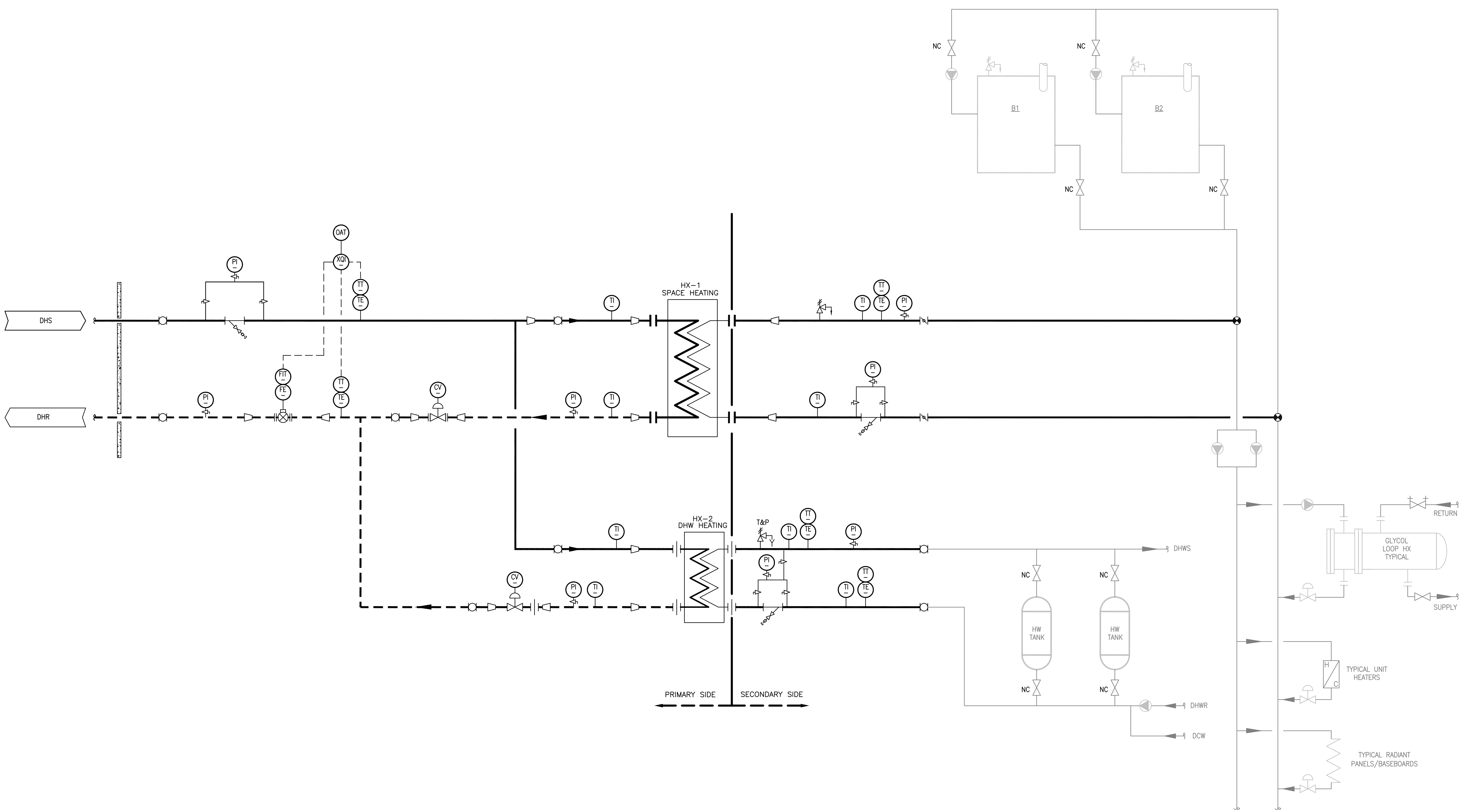
11. Elijah Smith Federal Building

The Elijah Smith Federal Building was built in 1991 and has four floors plus underground parking. The boiler equipment is located in the penthouse mechanical room (5th Floor). Three oil-fired and one electric boiler provide the hot water and glycol for the heating of the building. Glycol is used for the perimeter heating, air handling coil loops, and the heating of the first floor, loading bay, lobby and parkade. The radiant panels and reheat coils are served by hot water. The ventilation is all constant volume. One oil-fired steam boiler provides direct spray for humidification. Domestic hot water is provided by heat exchanger and tank off the boiler heating loop with an electric back-up heater. There is a pipe chase all the way to the parkade level and it is suspected that the heating system has a full reverse return but this would need to be verified at the design stage.

12. Closeleigh Manor (information is from A Review of the Heating Requirements of Closeleigh Manor and a Comparison to the Athletes Village Energy centre)

The Closeleigh Manor was built in 1988 to an R-2000 standard. The building is a three storey structure that is primarily residential space (30 suites) with a small portion of commercial space. The space heating system is served by five oil-fired boilers. The domestic hot water is served by oil-fired tanks.

III.ii Energy Transfer Station Schematics



INSTRUMENTATION LEGEND

OAT	OUTDOOR AIR TEMPERATURE SENSOR
CV	CONTROL VALVE
XQI	ENERGY METER
TT	TEMPERATURE TRANSMITTER
TE	TEMPERATURE ELEMENT
PI	PRESSURE INDICATOR
TI	TEMPERATURE INDICATOR

SYMBOLS LEGEND

WELDED BALL VALVE (PRIMARY)
STRAINER
PRESSURE RELIEF/SAFETY VALVE
BUTTERFLY VALVE
PUMP
REDUCER
UNION CONNECTION
CAP
FLOW METER
TIE−IN POINT
PIPE BREAK
FLOW ARROW
GATE VALVE
BALANCING VALVE
NEW PIPING
EXISITING PIPING

CONCEPTUAL ONLY
NOT FOR CONSTRUCTION

REVISIONS

DATE	REMARKS	NO.
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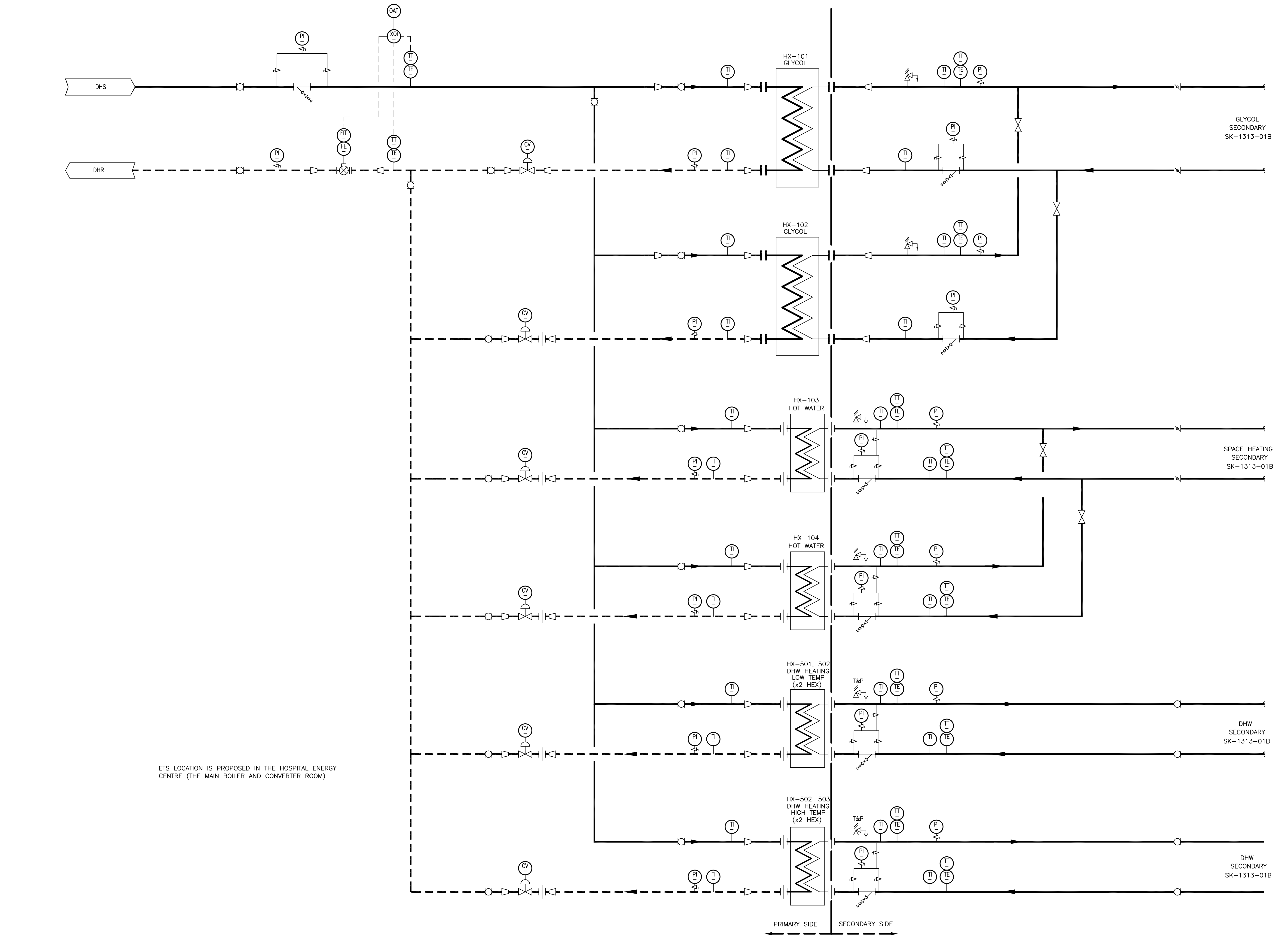
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453−3410
FAX: (780) 453−3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
TYPICAL BUILDING ENERGY TRANSFER STATION HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: D. DOHERTY	JOB NO.: 211313
APPR: _	DATE: JULY 23/2012
DWG NO.: SK−1313−TYP	



ETS LOCATION IS PROPOSED IN THE HOSPITAL ENERGY CENTRE (THE MAIN BOILER AND CONVERTER ROOM)

INSTRUMENTATION LEGEND

OAT	OUTDOOR AIR TEMPERATURE SENSOR
CV	CONTROL VALVE
XQI	ENERGY METER
TT	TEMPERATURE TRANSMITTER
TE	TEMPERATURE ELEMENT
PI	PRESSURE INDICATOR
TI	TEMPERATURE INDICATOR

SYMBOLS LEGEND

- WELDED BALL VALVE (PRIMARY)
- STRAINER
- PRESSURE RELIEF/SAFETY VALVE
- BUTTERFLY VALVE
- PUMP
- REDUCER
- UNION CONNECTION
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- FLOW METER
- TIE-IN POINT
- PIPE BREAK
- FLOW ARROW
- GATE VALVE
- NEW PIPING
- EXISITING PIPING

CONCEPTUAL ONLY
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REVISIONS

DATE	REMARKS	NO.
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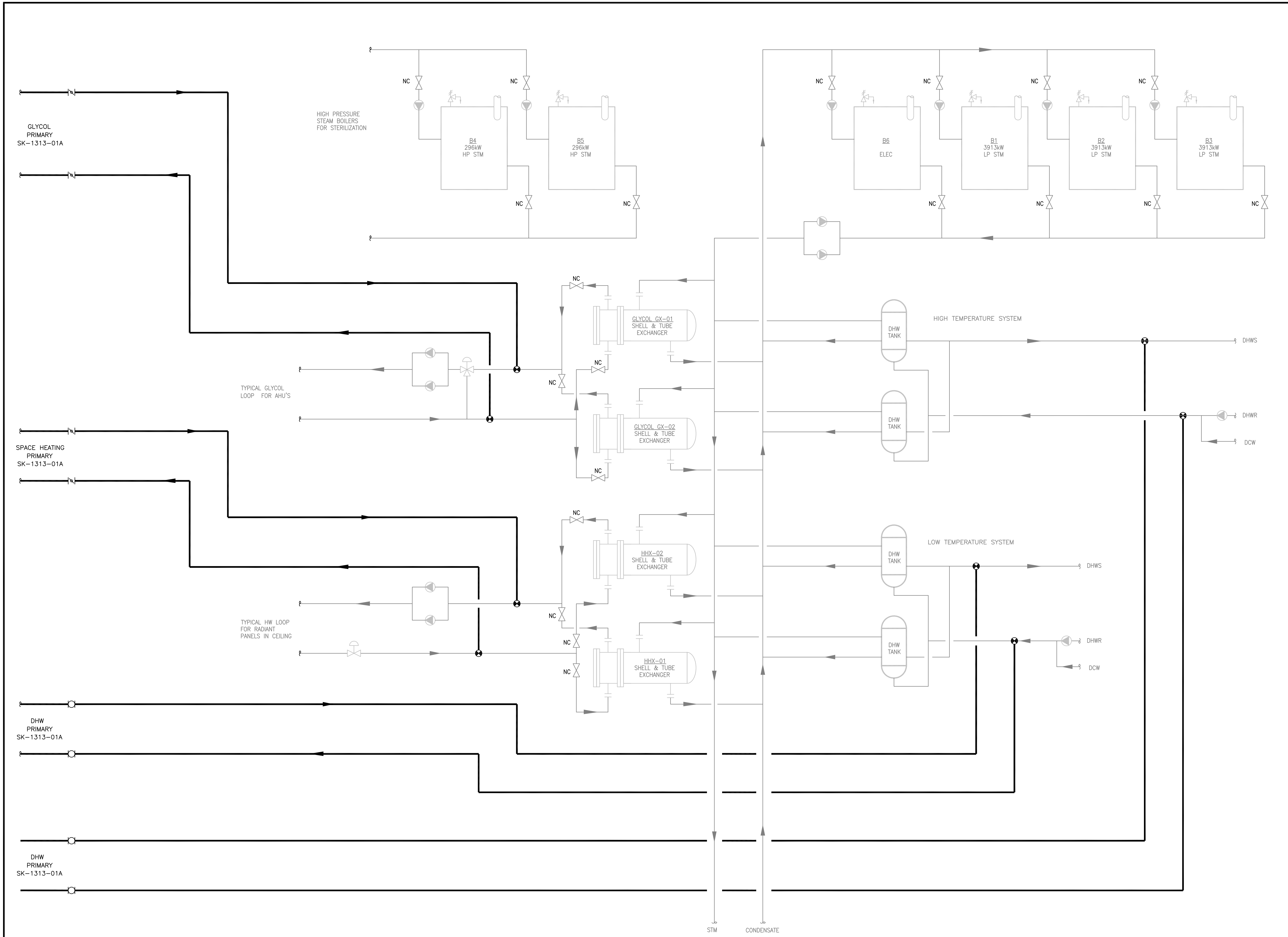
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
WHITEHORSE GENERAL HOSPITAL ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK-1313-001A	



INSTRUMENTATION LEGEND

OAT	OUTDOOR AIR TEMPERATURE SENSOR
CV	CONTROL VALVE
XQI	ENERGY METER
TT	TEMPERATURE TRANSMITTER
TE	TEMPERATURE ELEMENT
PI	PRESSURE INDICATOR
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SYMBOLS LEGEND

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- NEW PIPING
- EXISITING PIPING

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REVISIONS

DATE	REMARKS	NO.
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YUKON ENERGY

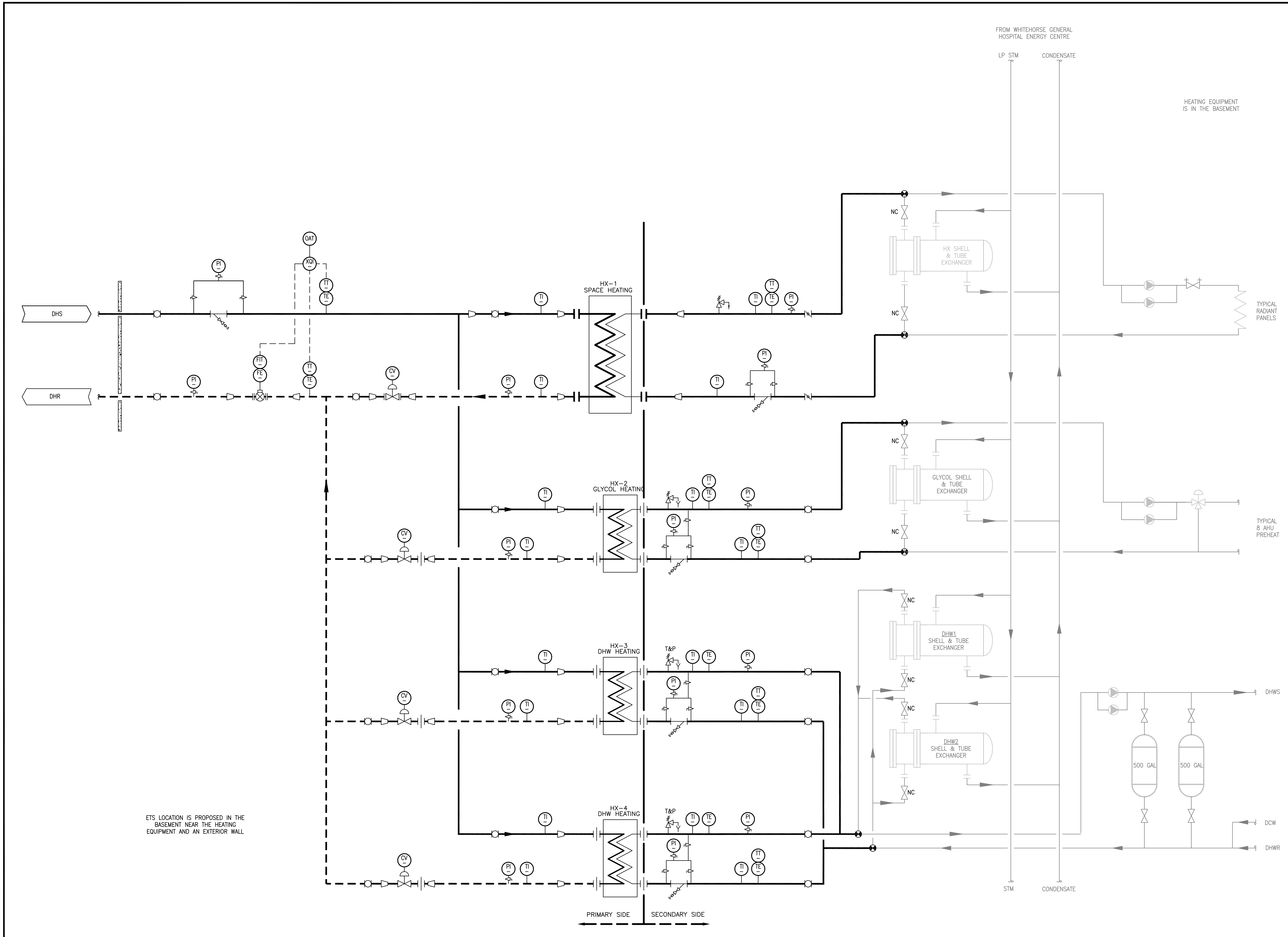
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
WHITEHORSE GENERAL HOSPITAL ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012

DWG NO.: SK-1313-001B



INSTRUMENTATION LEGEND

- OAT — OUTDOOR AIR TEMPERATURE SENSOR
- CV — CONTROL VALVE
- XQI — ENERGY METER
- TT — TEMPERATURE TRANSMITTER
- TE — TEMPERATURE ELEMENT
- PI — PRESSURE INDICATOR
- TI — TEMPERATURE INDICATOR

SYMBOLS LEGEND

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- PRESSURE RELIEF/SAFETY VALVE
- BUTTERFLY VALVE
- PUMP
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- FLOW ARROW
- GATE VALVE
- BALANCING VALVE
- NEW PIPING
- EXISITING PIPING

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REVISIONS

DATE	REMARKS	NO.
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YUKON ENERGY

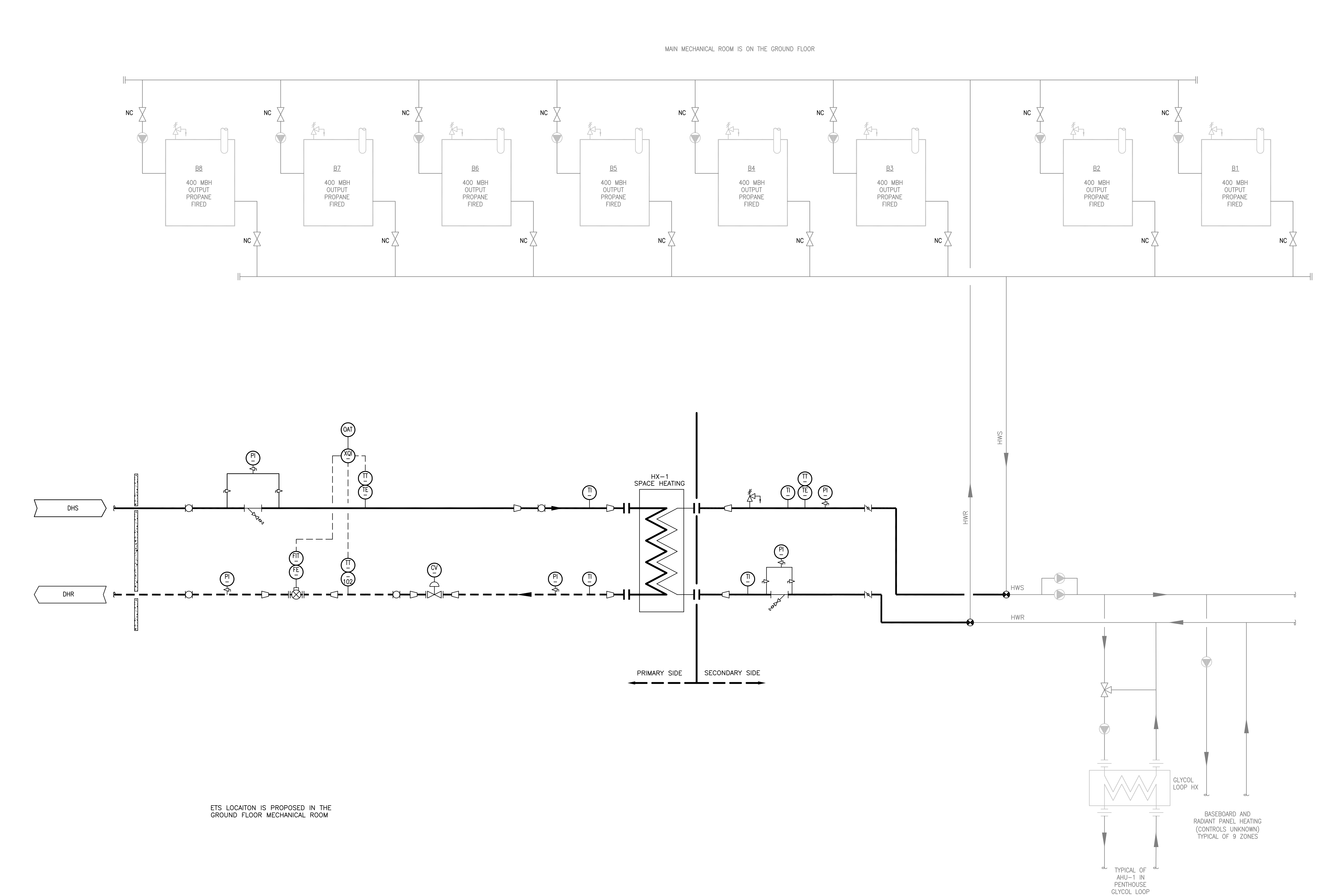
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
THOMSON CENTRE ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012

DWG NO.: SK-1313-002



INSTRUMENTATION LEGEND

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- CV — CONTROL VALVE
- XQI — ENERGY METER
- TT — TEMPERATURE TRANSMITTER
- TE — TEMPERATURE ELEMENT
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SYMBOLS LEGEND

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- FLOW ARROW
- GATE VALVE
- NEW PIPING
- EXISITING PIPING

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REVISIONS

DATE	REMARKS	NO.
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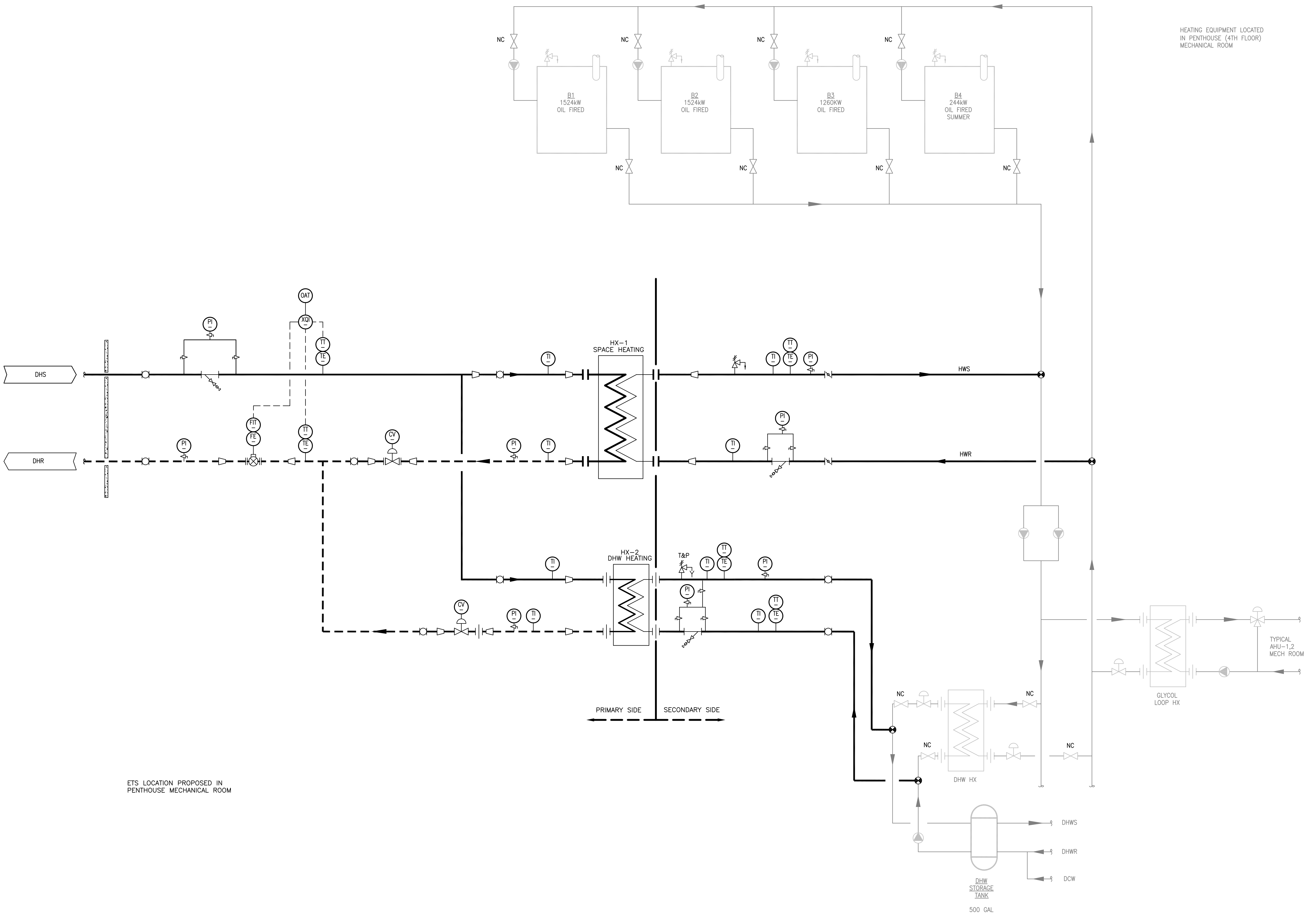
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE: **WHITEHORSE COMMUNITY HEATING STUDY**

SHEET TITLE: **EDUCATION BUILDING ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC**

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK-1313-003	



INSTRUMENTATION LEGEND

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- CV — CONTROL VALVE
- XQI — ENERGY METER
- TT — TEMPERATURE TRANSMITTER
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SYMBOLS LEGEND

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- EXISITING PIPING

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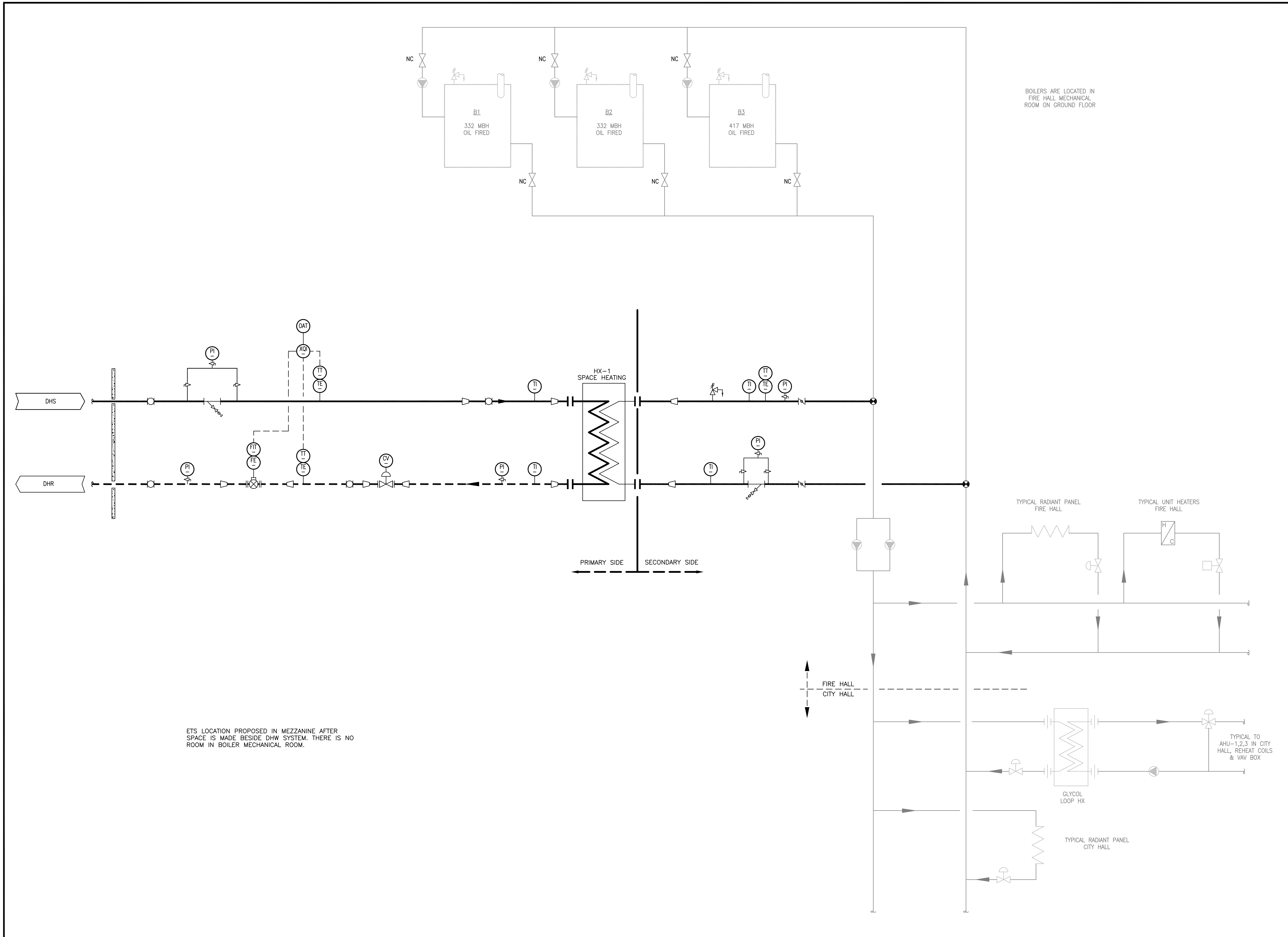
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
YUKON TERRITORY GOV. ADMIN BLDG ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK-1313-004	



INSTRUMENTATION LEGEND

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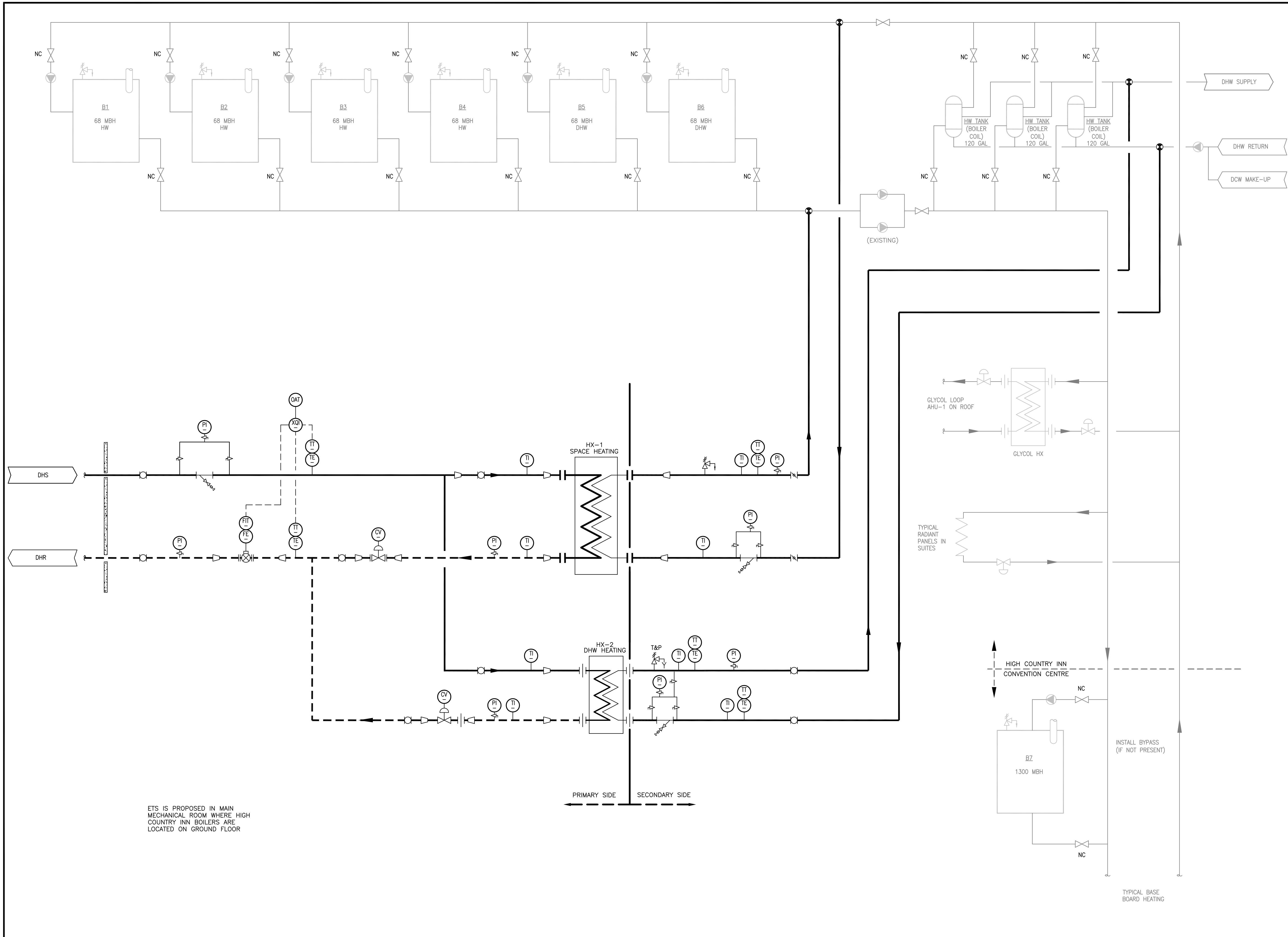
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
CITY HALL / FIRE HALL ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK-1313-005	



INSTRUMENTATION LEGEND

- OAT — OUTDOOR AIR TEMPERATURE SENSOR
- CV — CONTROL VALVE
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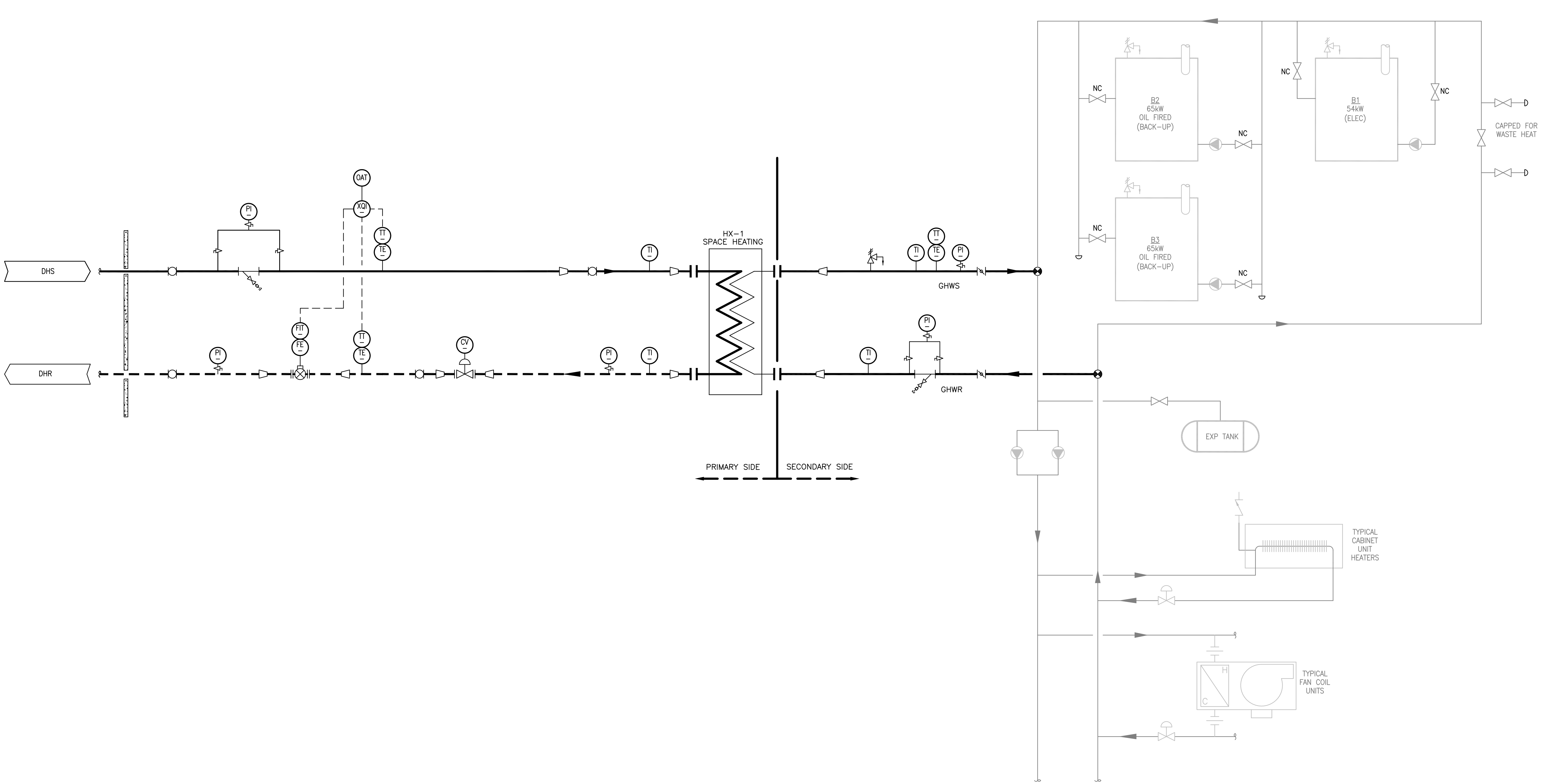
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453-3410
FAX: (780) 453-3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
HIGH COUNTRY INN ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR.: _	DATE: MAY 30/2012
DWG NO.: SK-1313-006	



INSTRUMENTATION LEGEND

- OAT — OUTDOOR AIR TEMPERATURE SENSOR
- CV — CONTROL VALVE
- XQI — ENERGY METER
- TT — TEMPERATURE TRANSMITTER
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SYMBOLS LEGEND

- WELDED BALL VALVE (PRIMARY)
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- PRESSURE RELIEF/SAFETY VALVE
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- EXISITING PIPING

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DATE	REMARKS	NO.
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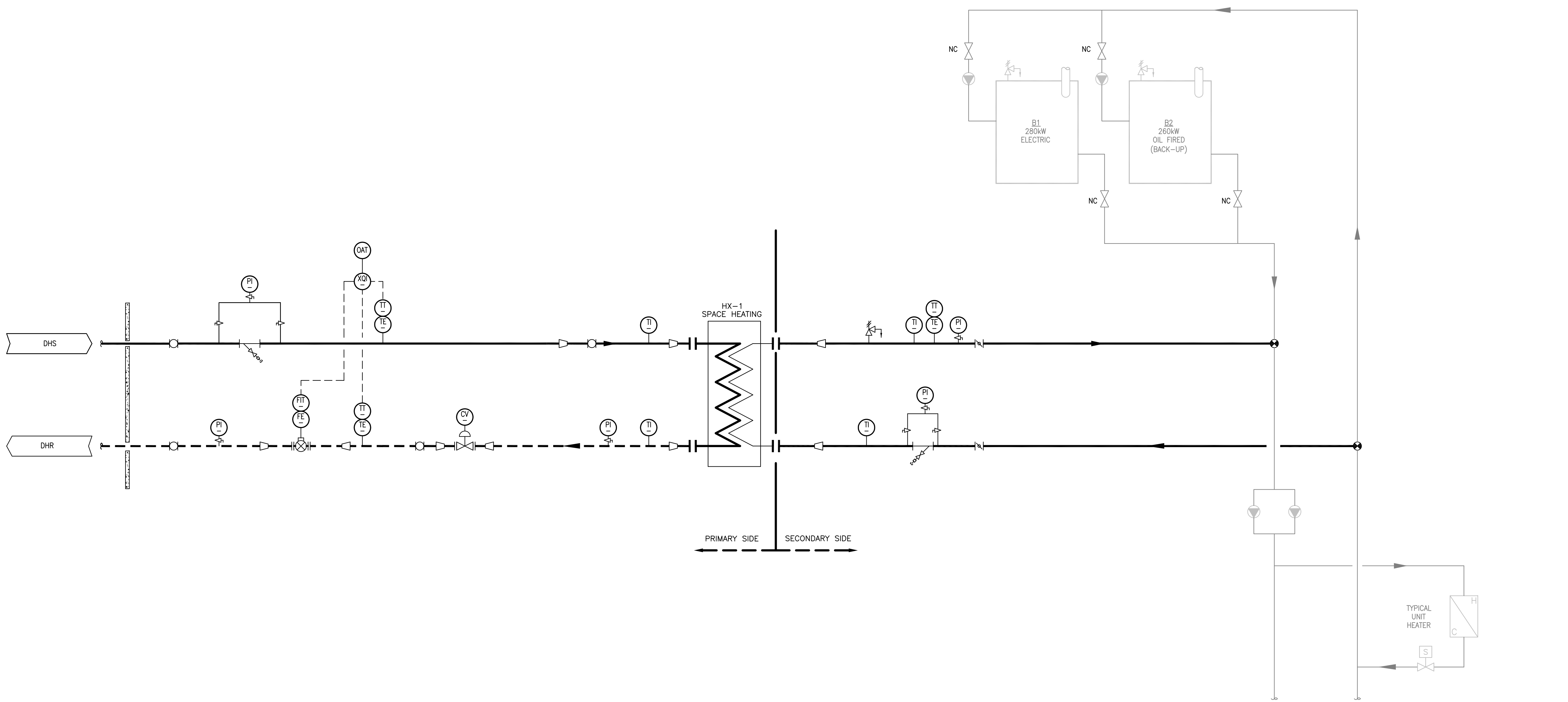
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
YEC OFFICE ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK–1313–007	



INSTRUMENTATION LEGEND

- OAT — OUTDOOR AIR TEMPERATURE SENSOR
- CV — CONTROL VALVE
- XQI — ENERGY METER
- TT — TEMPERATURE TRANSMITTER
- TE — TEMPERATURE ELEMENT
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SYMBOLS LEGEND

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- STRAINER
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- GATE VALVE
- NEW PIPING
- EXISITING PIPING

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DATE	REMARKS	NO.
–	–	–

YUKON ENERGY

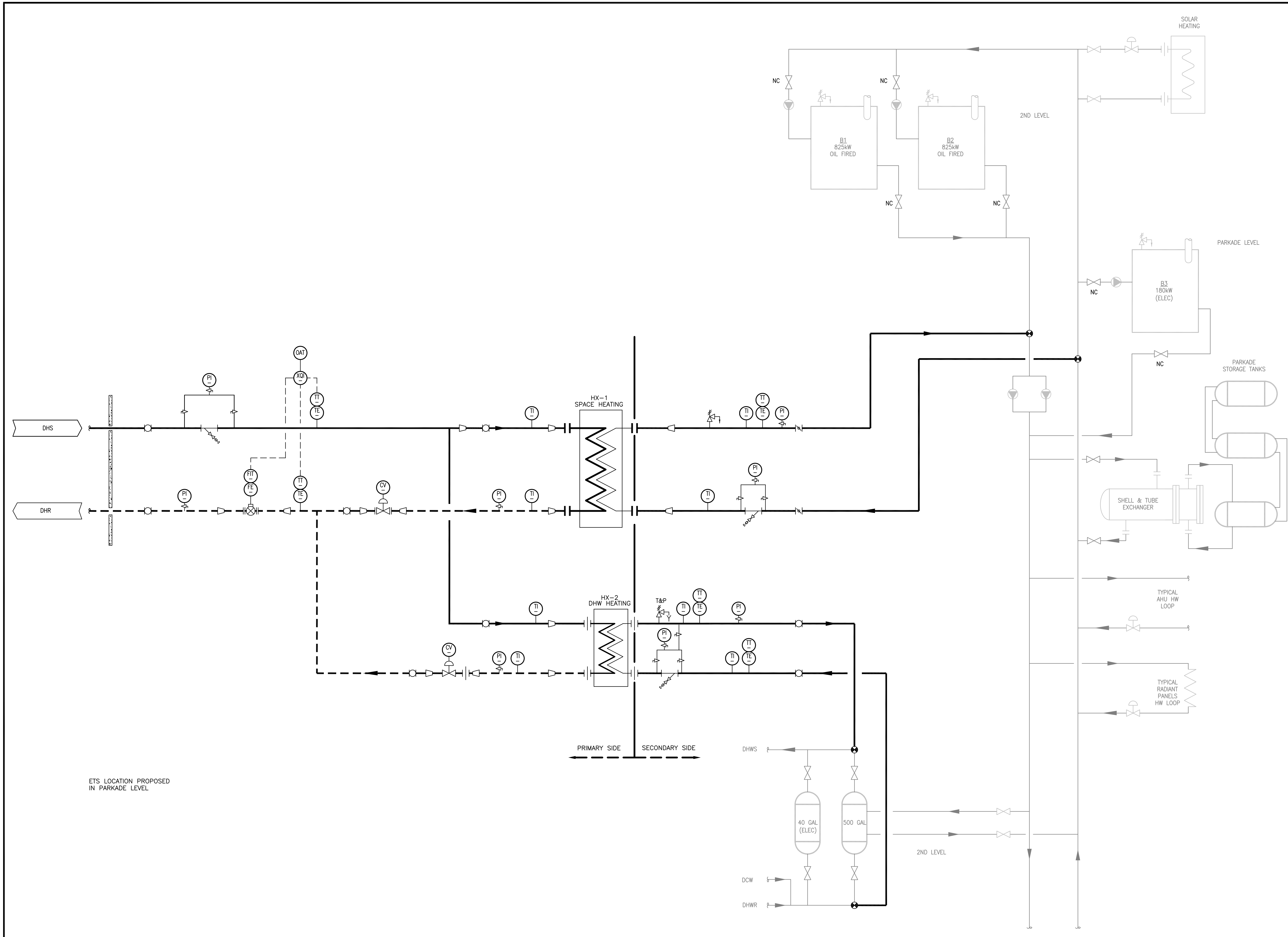
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
YEC P125 HYDRO GENERATING FACILITY ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012

DWG NO.: SK–1313–008



INSTRUMENTATION LEGEND

OAT	OUTDOOR AIR TEMPERATURE SENSOR
CV	CONTROL VALVE
XQI	ENERGY METER
TT	TEMPERATURE TRANSMITTER
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SYMBOLS LEGEND

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–	–	–

YUKON ENERGY

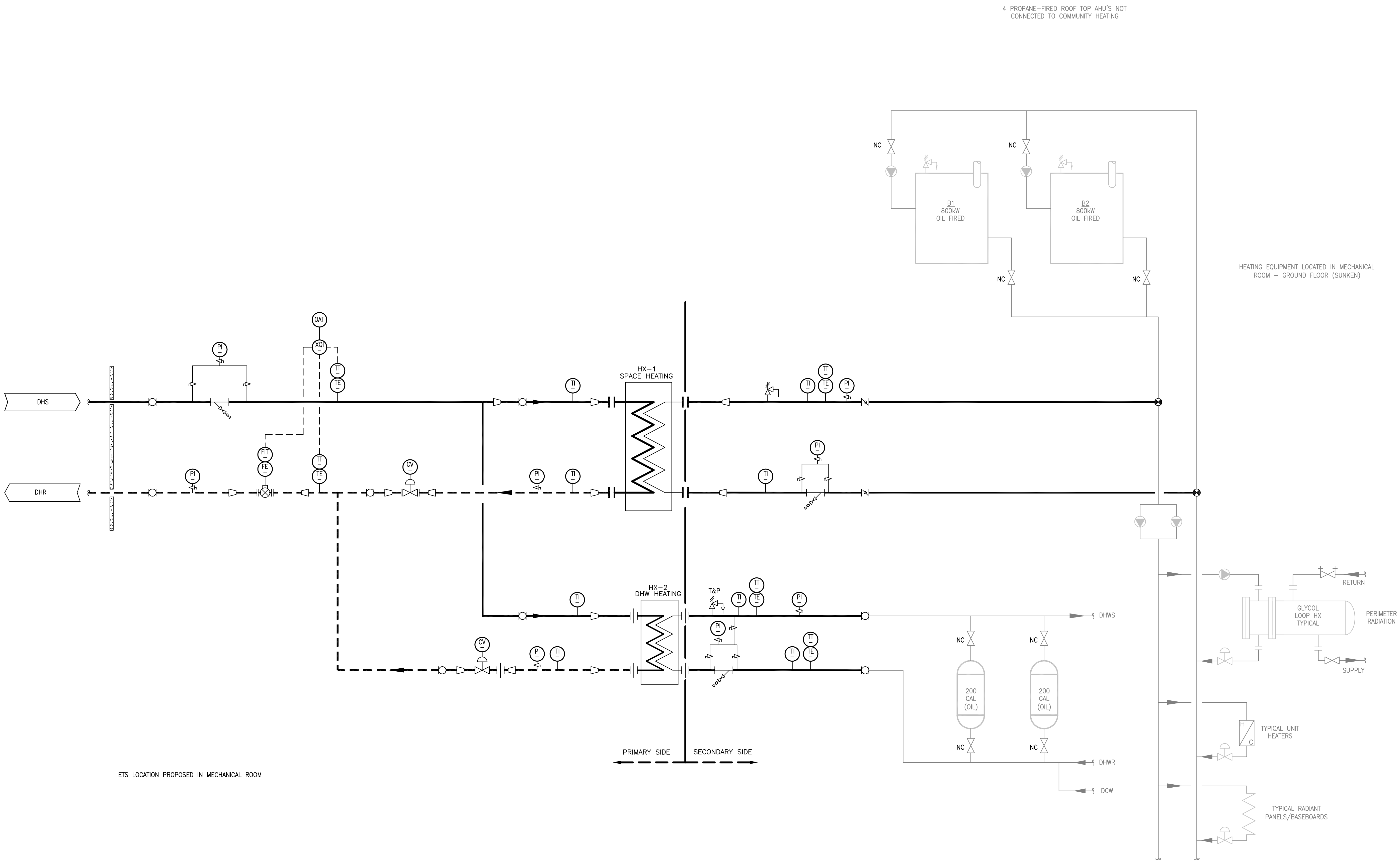
FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
LAW COURTS (YUKON JUSTICE BLDG) ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012

DWG NO.: SK–1313–009



INSTRUMENTATION LEGEND

- OAT — OUTDOOR AIR TEMPERATURE SENSOR
- CV — CONTROL VALVE
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- NEW PIPING
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DATE	REMARKS	NO.
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YUKON ENERGY

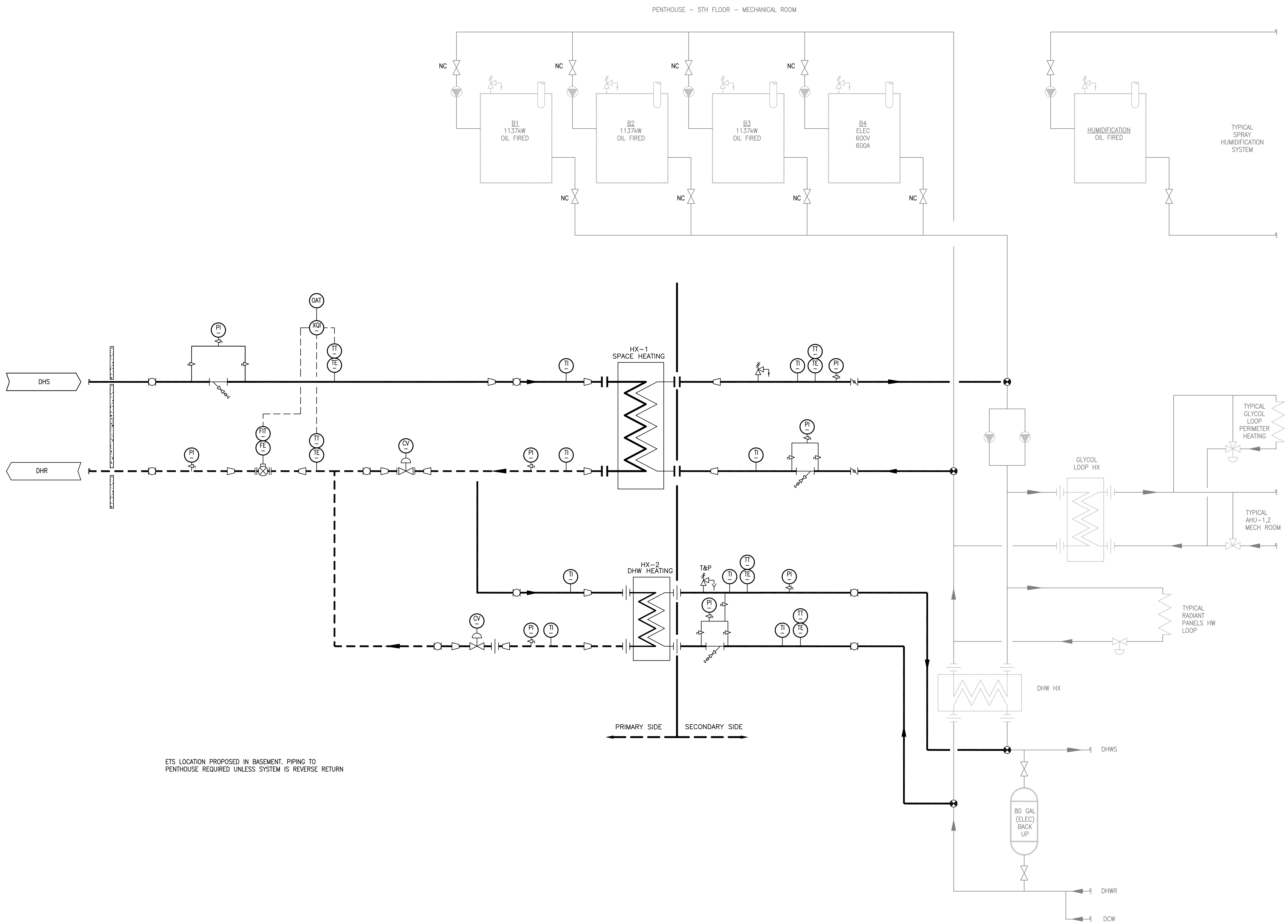
FVB ENERGY INC

13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
WHITEHORSE ELEMENTARY ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK–1313–010	



INSTRUMENTATION LEGEND

- OAT OUTDOOR AIR TEMPERATURE SENSOR
- CV CONTROL VALVE
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SYMBOLS LEGEND

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DATE	REMARKS	NO.	
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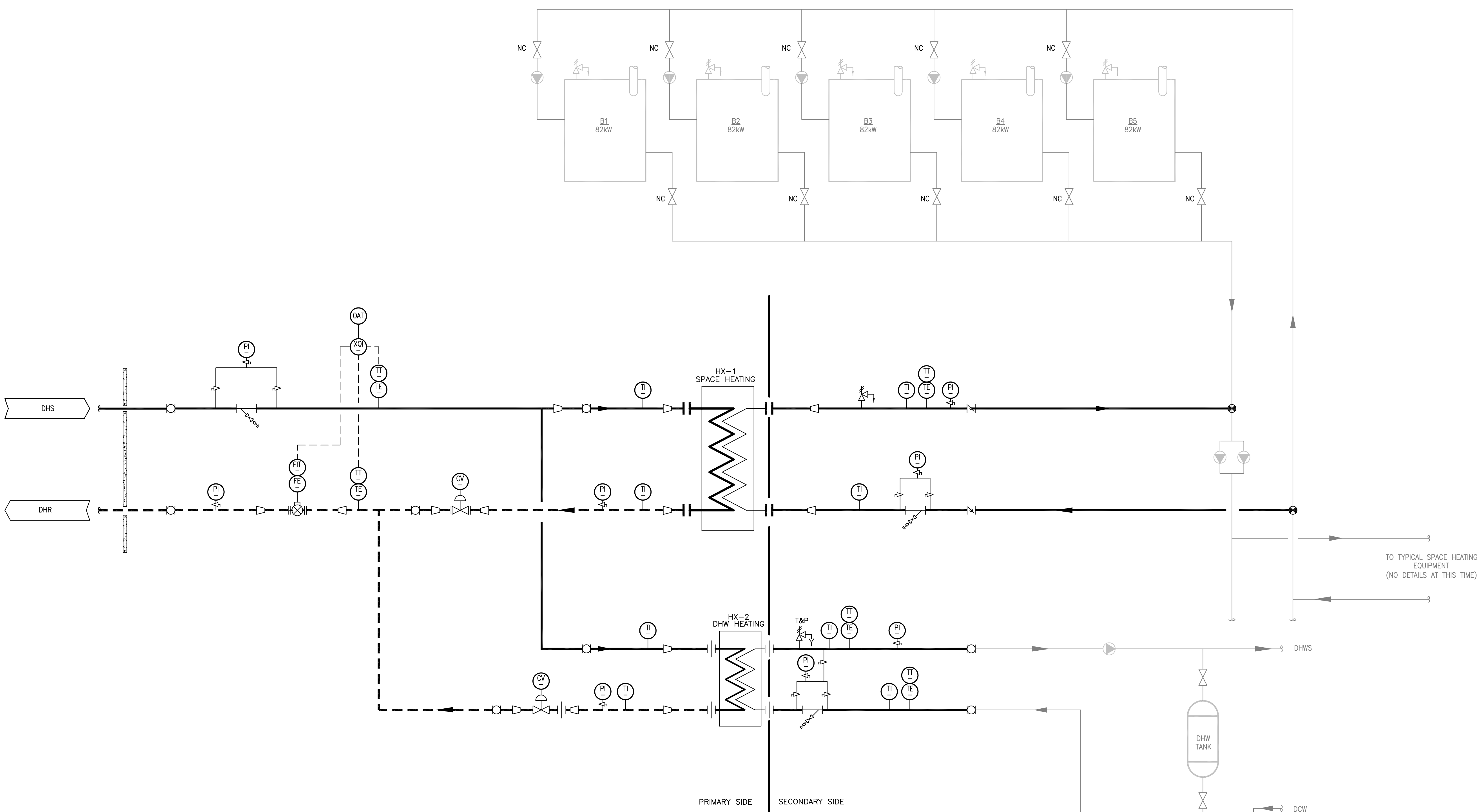
YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
ELIJAH SMITH FEDERAL BUILDING ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
DWG NO.: SK–1313–011	



INSTRUMENTATION LEGEND

OAT	OUTDOOR AIR TEMPERATURE SENSOR
CV	CONTROL VALVE
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DATE	REMARKS	NO.
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YUKON ENERGY

FVB ENERGY INC
13220 ST. ALBERT TRAIL, SUITE 350
EDMONTON, ALBERTA T5L 4W1
TEL: (780) 453–3410
FAX: (780) 453–3682

PROJECT TITLE:
WHITEHORSE COMMUNITY HEATING STUDY

SHEET TITLE:
CLOSELEIGH MANOR ENERGY TRANSFER STATION PRELIMINARY HEATING SCHEMATIC

DGN: S. WOLTER	SCALE: N.T.S.
DWN: V. DION	JOB NO.: 211313
APPR: _	DATE: MAY 30/2012
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