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REPORT

Geoscience BC

Clarke Lake
Geothermal Pre-Feasibility Study

August 2019

CANADA BEST MANAGED COMPANIES Platinum member

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Executive Summary

Following the release of two research studies on the high-level feasibility of geothermal energy in the Clarke Lake Reservoir area near Fort Nelson, BC, this engineering pre-feasibility study aims to further assess the potential implementation of a project from a site servicing / development perspective, as well as assessing the potential customer base for power and potential heat recovery, to help inform whether a more detailed feasibility study can be justified. All cost estimates in this report are Class D (± 50%), including any payback estimates, based on the assumed concept development. Different vendors of varying scales of binary geothermal plant employing the Organic Rankine Cycle (ORC) were investigated. This technology produces electricity as well as the potential exploitation of the waste heat as an additional revenue stream. Two potential vendors of medium-scale ORC technology applicable to the potential Clarke Lake project are reviewed for potential costs and site development requirements: Ormat Technologies Inc. and Turboden.

The potential site location scenarios are selected based on the geothermal favourability scores presented in one of the previous research studies. Two main scenarios are presented and are called Site A and Site B. Site A is just east of the town of Muskwa (approximately 10 km south of Fort Nelson), and Site B is further southeast. These locations are largely speculative at this stage and are presented for illustration of requirements and considerations. For both sites, the site development requirements are discussed, and estimates at quantifying the efforts and costs are included. Since significant development of forested land is likely required, the environmental implications are identified with all potential concerns listed along with the likely requirements for environmental assessment, permitting, and compensation.

The BC Hydro Standing Offer Program (SOP) is identified as a potential customer for electricity sales. This program is not available to the Fort Nelson area and is currently suspended but since it represents the most recent available avenue for electricity sales in BC, it is used in this report as an example. The capacity limit for this program was 15 MW, which is the size considered for this study. Under the BC Hydro SOP, the potential annual revenue for a 15 MW plant is estimated at $12,740,000. The concept of a district heating network to sell heat to nearby buildings in Fort Nelson and industrial customers is discussed, with revenues estimated at approximately $412,000/year, allowing for a simple payback starting at 35 years, which does not consider the cost of financing or any potential building retrofits required. A Northern Rockies Regional District (NRRD) community energy management plan identifies substantially larger heat consumption in the area, but it is unclear how much of that would be in a proximity to the geothermal plant to be practical and cost-effective, so more investigation is required to determine this possibility. The nearby gas transmission plant owned by Enbridge Inc is identified as a potential customer for both electricity and heat, but this will require more investigation and direct engagement to quantify as an opportunity, and they may be using low cost natural gas to produce their own electricity and heat, making them an unlikely customer unless a low-carbon source of energy becomes their priority.

As the geothermal plant is a source of low-carbon heat and electricity, it may be marketed to attract new industry to the area. Potential new customers are speculated upon. For electricity, there may be an opportunity to attract cryptocurrency mining operations to the area, although it is not clear whether cryptocurrency miners can be considered long term customers. Competing with BC Hydro industrial rates may pose a challenge, however, as they are much lower than the BC Hydro SOP purchase price, so there could be diminishing returns to higher plant capacities. Greenhouses are identified as a potential customer for the waste heat from the plant, with an estimate on their consumption from the Government of Manitoba providing a revenue estimate of $15,600/year from a 1000 m^2 greenhouse. Other potential heat recipients are identified, but at this time, it is purely speculative as to their feasibility.

A total plant development cost estimate is then developed. Since the previous studies identified an achievable well flow rate in the range of 30 kg/s to 100 kg/s, this produces two scenarios at these extremes; one with 47 wells required, and one with 15 wells required. Since the wells are a major driving cost of the plant, these two scenarios are looked at separately. The results show a cost estimate in the range of $139 million to $285 million ($CAD). Considering only the potential revenue from the BC Hydro SOP and an estimate for the annual operations and maintenance costs, this produces a simple payback range of 12-24 years for plant construction and commissioning.

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1 Introduction

1.1 BACKGROUND AND GEOSCIENCE BC

"Geoscience BC is an independent, not-for-profit organization whose mission is to generate earth science in collaboration with First Nations, local communities, governments, academia, and the resource sector. By providing geological data and geoscience knowledge, Geoscience BC work contributes to investment decisions and socio-economic opportunities in British Columbia."

One of the strategic focus areas of Geoscience BC is Energy. Geoscience BC has previously commissioned two research studies with the purpose of quantifying the potential amount of electrical energy that can be harnessed from the nearby geothermal resources, and the cost of that energy. The first study focuses on the techno-economic assessment of the Western Canada Sedimentary Basin (WCSB), while the second is a geological assessment of the Clarke Lake Reservoir, which is in the WCSB and was considered a promising location due to its geological characteristics, the nearby town of Fort Nelson, and existing natural gas development that provides significant geological data. The observations and conclusions of a third report authored by KWL's Monk et al. that used a modelling methodology known as Geothermal Electricity Technology Evaluation Model (GETEM) was reviewed for comparison to the results of this study.

These studies are as follows:

- *Techno-Economic Assessment of Geothermal Energy Resources in the Western Canada Sedimentary Basin, Northeastern British Columbia* – Palmer-Wilson et al., 2018,
- *Clarke Lake Gas Field Reservoir Characterization* – Renaud et al., 2018
- *An Assessment of the Economic Viability of Selected Geothermal Resources in British Columbia Geoscience BC Report 2015-11* – Monk et al., 2015 (Section 7., Observations and Conclusions, reviewed for comparison)

The research projects are focused on assessing the geothermal resource capacity from the Clarke Lake Reservoir and identifying a suitable low-temperature energy conversion technology such as the Organic Rankine Cycle (ORC). This would provide stable, low-carbon electrical generation and a potentially serviceable waste heat stream that could be recovered for use by nearby customers. These studies are discussed further in Section 1.3.

Geoscience BC has commissioned Associated Engineering (AE) to conduct this pre-feasibility study to further assess the feasibility of implementing a project from a site servicing perspective, as well as assessing the potential customer base for power and potential heat recovery, to help inform whether a more detailed feasibility study can be justified. All cost estimates in this report are Class D (± 50%), including any payback estimates, based on the assumed concept development.

1.2 SCOPE OF WORK

The work plan is divided into the following phases:

1. Review of background research studies.
2. Identify potential power plant technology vendors and determine technical parameters and servicing requirements.
3. Produce a desktop concept design of a potential power plant and servicing infrastructure, and estimate the costs involved.
4. Identify potential customers that already exist for both electricity and heat by surveying the Clarke Lake/Fort Nelson area and analyzing the electrical and heating loads present for revenue estimations. Provide a cost estimate for connection.
5. Review and summarize the technical, legal and sales framework for potential power purchase agreements.
6. Identify potential new customers that could exist in the future that may be compatible with the output of the geothermal project.
7. Outline the environmental permitting and approvals considerations.

1.3 REVIEW OF EXISTING RESEARCH STUDIES

As mentioned above, there are three main studies on the potential for a Clarke Lake geothermal project.

***Techno-Economic Assessment of Geothermal Energy Resources in the Western Canada Sedimentary Basin, Northeastern British Columbia – Palmer-Wilson et al. –* 2018**

The study assesses geothermal energy resources in the Western Canada Sedimentary Basin section located in northeastern British Columbia, Canada. Palmer-Wilson et al. use data available on geological criteria and economic criteria relevant to the favourability of geothermal power to produce a geothermal power development favourability map. According to this algorithm, regions of high favourability show a better opportunity for geothermal power development as compared to regions of low favourability. The criteria are put together in a weighted summation to produce the favourability score for the locations studied within the Western Canada Sedimentary Basin.

The geological and economic criteria and their relative weights in the favourability score are as follows:

- Geological Criteria (50% of score overall):
  - Temperature of geothermal resource (50% of geological weight, 25% overall).
  - Indicated Aquifer – evidence of permeable aquifers (50% of geological weight, 25% overall).
- Economic Criteria (50% of score overall):
  - Gas Activity – Potential for natural gas industry as a customer (27.3% of economic criteria, 13.7% overall).
  - Electrical Infrastructure – proximity to transmission lines and substations (27.3% of economic criteria, 13.7% overall).
  - Proposed Electrical Infrastructure – electrical infrastructure in planning (18.1% of economic criteria, 9.1% overall).
  - Towns and Communities – proximity to communities for worker housing and potential for excess heat sales (27.3% of economic activity, 13.7% overall).

The data is geographical in nature, and thus can produce a map as a product. Further details on the sources of the data can be found in Palmer-Wilson et al, 2018.

Using the produced favourability map, Palmer-Wilson et al. show four regions of high favourability. The Clarke Lake Reservoir area is one of those regions. Within the Clarke Lake Reservoir area, there are regions of higher favourability, which will be further explored in Section 2.2 below.

The study suggests that the BC Hydro Standing Offer Program (SOP) is the most likely opportunity to sell electricity, and since this program is limited at 15 MW, this is power of the high-level model plant studied. The viability of the BC Hydro SOP will be explored further in this report in Sections 2.3 and 5.1.1.

Since there was limited data on achievable flow rates for the potential geothermal wells, the authors cite studies to deduce a range of 30 kg/s to 100 kg/s, which produces a high and low value for the number of wells required that are treated as separate cases. The achievable well flow rates have a significant impact on the total capital costs as shown in Section 7 below.

The study also estimates capital costs for the construction of such a project and produces financial indicators in net present values, internal rates of return, and a levelized cost of energy. Upon review of these numbers, the capital costs in Table 15 could not be reconciled using the inputs provided in Table 12 and Equation 10, possibly indicating an overestimate in the total capital costs. Additionally, in the 30 kg/s production flow rate scenario, despite a significant capital cost increase at the same revenue compared to the 100 kg/s scenario, the net present value increases, which is not intuitive and should be confirmed with the authors.

With the high capital costs, the study concludes that in addition to an electricity SOP, selling waste heat to nearby customers (potentially greenhouses) is key to making this project viable.

***Clarke Lake Gas Field Reservoir Characterization* – Renaud et al. 2018:**

This study focuses on the key geological variables controlling the flow of hot water within the Clarke Lake Reservoir. Using flow simulations, the viability of a 25-year geothermal plant is assessed. The flow simulations show that 300 kW of electrical power was able to be produced using a well doublet, and 2400 kW of electrical power was produced using a four injector and eight producer well configuration.

***An Assessment of the Economic Viability of Selected Geothermal Resources in British Columbia Geoscience BC Report 2015-11* – Monk et al., 2015 (Section 7., Observations and Conclusions, reviewed for comparison)**

Section 7 (Observations and Conclusions) of this report contains material relevant to this study. The GETEM models showed that the highest levelized cost of energy (LCOE - net present value of the unit-cost of electrical energy over the lifetime of the plant) was the highest of the nine investigated favourable sites at the Clarke Lake location at 0.297CAD$/kWh. This was for a potential 34 MW plant. An additional scenario of Clarke Lake at 5 MW was considered, and the LCOE was estimated at 0.332CAD$/kWh. The authors also note that the cost of drilling wells during the various phases of a geothermal project has a significant impact on the LCOE.

1.4 GEOTHERMAL ENERGY AND THE WESTERN CANADA SEDIMENTARY BASIN

Geothermal energy is the exploitation of stored energy in the form of heat beneath the surface of the earth, usually in the form of hot water or steam. Canada currently has no installed geothermal electrical generation. British Columbia (BC) features geological settings that allow for exploiting geothermal energy resources, which makes it a focus for potential geothermal energy development.

The Clarke Lake area is situated in the Western Canadian Sedimentary Basin (WCSB), shown in Figure 1-1, which is a geopressured type of geothermal resource. Geopressured resources derive their energy from pressurization of fluids and gases by overlying sedimentary deposits. The WCSB is a relatively lower temperature region, so it receives less attention with regards to potential geothermal development. That said, significant oil and gas development in the region has provided a database of wells available from the BC Oil and Gas Commission, which can be used to estimate electrical and heating generation potential and were analyzed by Palmer-Wilson et al. 2018.

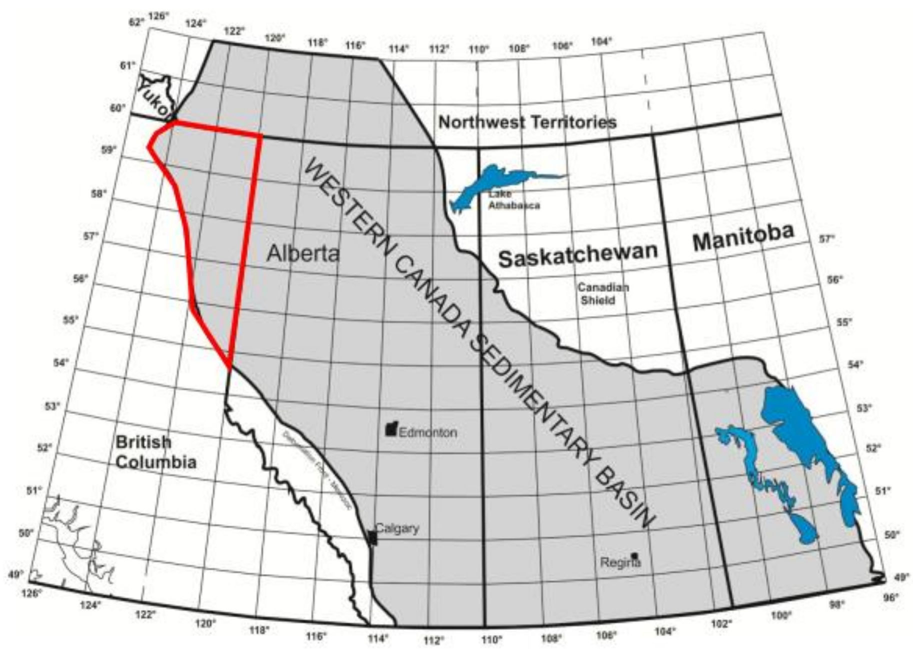
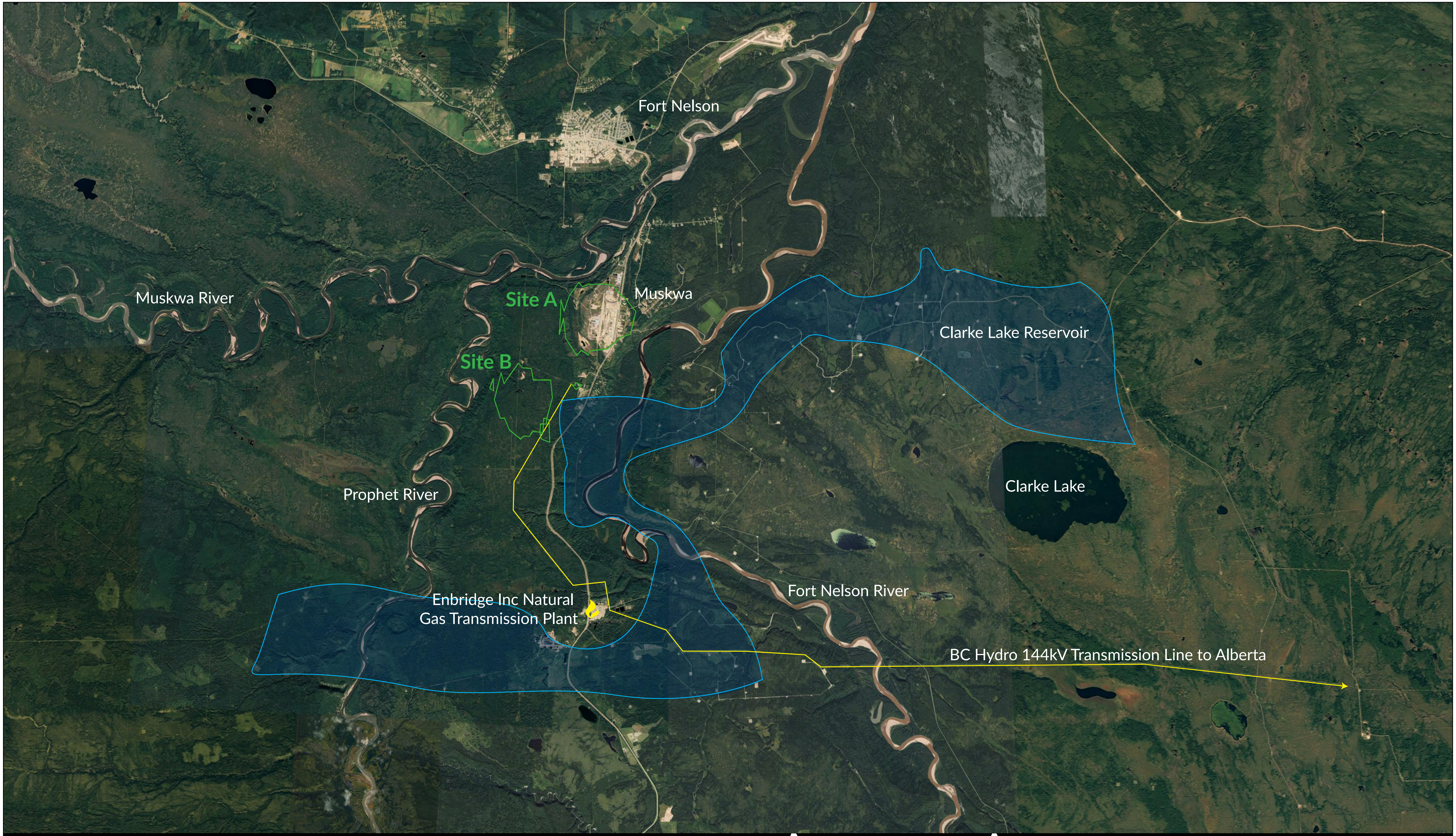


Figure 1-1
Location of the sites examined in Palmer-Wilson et al. – 2018

In the report, the authors present a high-level financial analysis of the region and determine that four areas highlight the best opportunities for geothermal development based on several key parameters (further detailed in Section 1.3 above). These areas were Horn River, Prophet River, Jedney, and Clarke Lake. As mentioned in the introduction, the focus of this report will be the feasibility of a geothermal power plant in the Clarke Lake area near Fort Nelson. Figure 1-2 shows the Clarke Lake Reservoir, Clarke Lake, the



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BC Hydro Transmission Line
Clarke Lake Reservoir
Top 10% Geothermal Favourability Contour from Palmer-Wilson et al.

PROJECT NO.: 2018-2262.000.005
DATE: August 2019

FIGURE 1-2: Site Location Options from Palmer-Wilser et al. 2018 Favourability Map shown with Clarke Lake Reservoir and BC Hydro Transmission Line

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Clarke Lake
Geothermal Plant Locations

nearby towns of Muskwa and Fort Nelson, as well as potential geothermal plant site locations and a BC Hydro transmission line which will be explained below. Reservoir extent GIS data was provided by Evan Renaud, M.Sc. Candidate at the University of Alberta.

2 Conceptual Power Plant Design Requirements

2.1 TECHNOLOGY AND VENDOR RESEARCH

2.1.1 Available Technology Options

There are three different power plant technologies that are used to convert geothermal fluid to electricity: dry steam, flash steam, and binary cycle technology.

Both dry steam and flash steam power plants require high temperature (typically 180 °C or more) water to function. Dry steam power plants use high temperature steam with no liquid component ('dry') out of the ground and directly into a turbine to produce electricity. Flash steam power plants are suited for when the production pressures are high enough that the produced fluid has a liquid component ('wet' steam, or very high-pressure hot water) so that the pressure must be lowered to turn it into a dry steam first ('flashing') prior to it entering the turbine.

As the reservoir temperature near Clarke Lake is estimated at 110°C, binary cycle power plant technology has been considered the most appropriate for further evaluation. This technology uses the Organic Rankine Cycle (ORC) to produce electricity from the geothermal resource. The geothermal fluid is pumped from the production well and passed through a heat exchanger where it transfers its heat to a pressurized secondary fluid with a much lower boiling point (example: iso-butane). This secondary fluid, known as the working fluid, then evaporates and expands through the turbines for electricity production. The working fluid is then condensed back into a liquid, pumped back up to pressure, and then enters the heat exchanger again. After the heat extraction, the cooler geothermal fluid is re-injected into the reservoir. Figure 2-1 illustrates the concept.

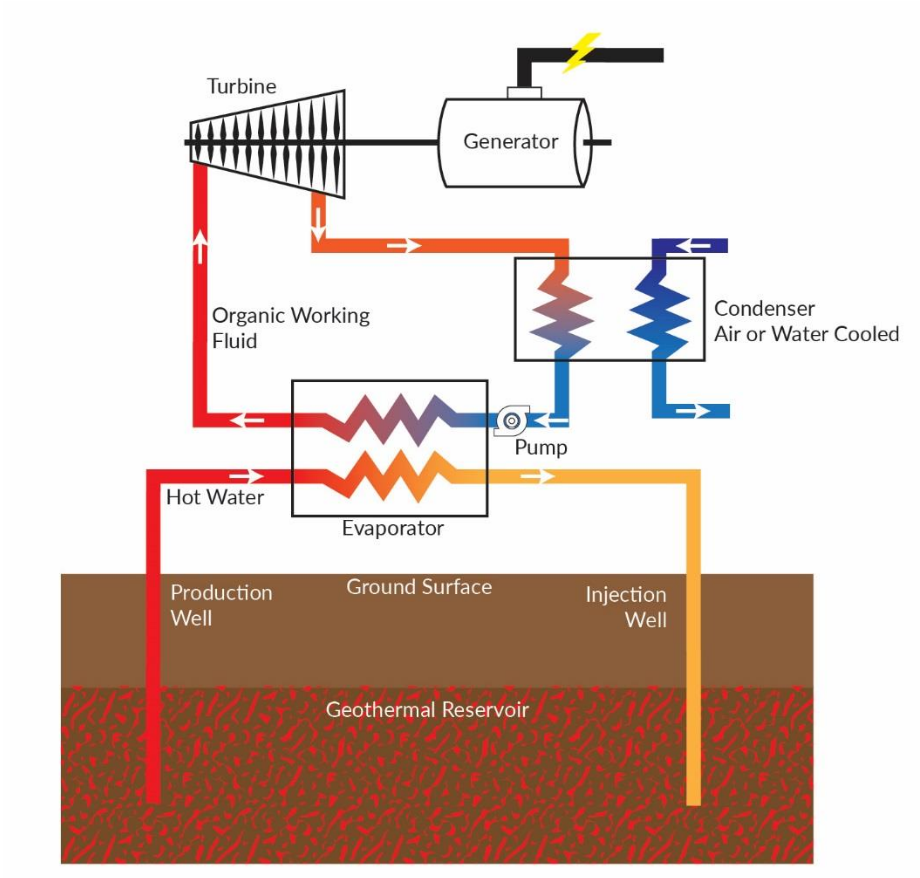


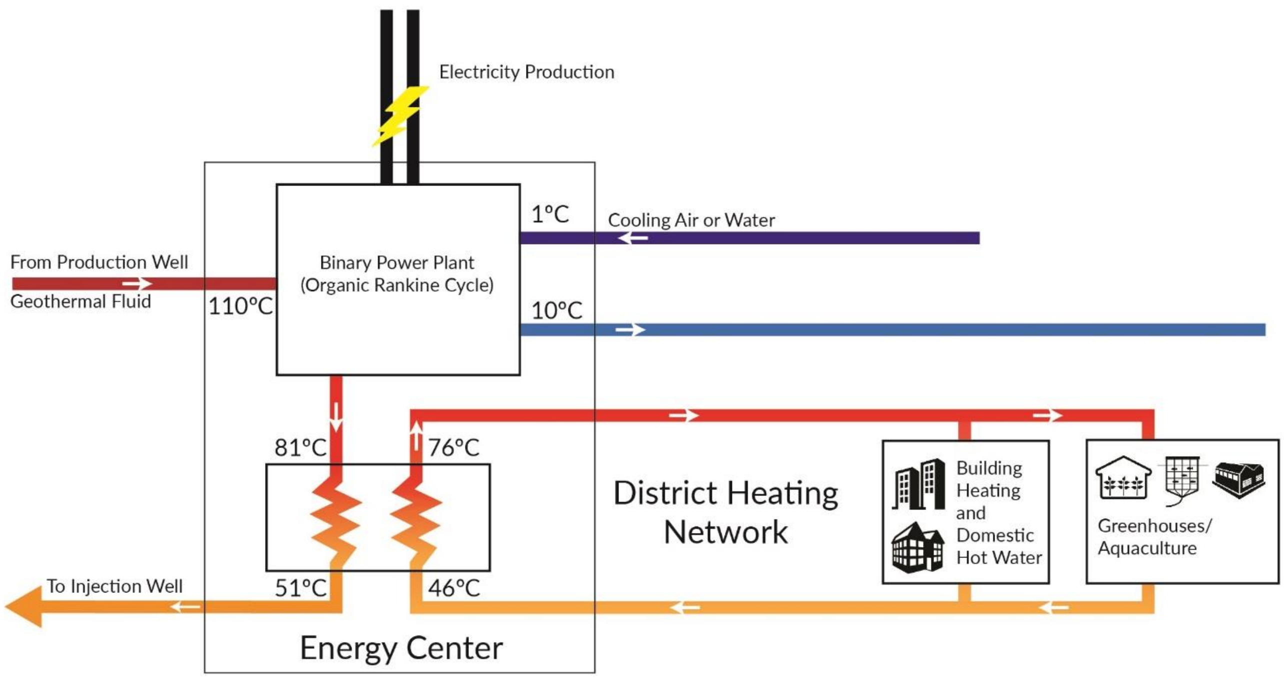
Figure 2-1
Binary Cycle Geothermal Power Plant Diagram

Several vendors of binary power plant technology were researched, and a summary is provided below in Section 2.1.3.

2.1.2 Power Generation Combined with District Heating Networks

Figure 2-2 shows a concept diagram of a geothermal binary power plant being operated in conjunction with a district heating network. After the Organic Rankine Cycle, the geothermal fluid still holds significant thermal energy (in this example, it is 81 °C, which was provided by an ORC vendor based on information provided on the Clarke Lake Reservoir as detailed in Section 7). There is also a significant amount of heat rejected from the condenser unit, but this is at a much lower temperature, so is not as valuable as it would likely require the use of heat pumps to be of any use. For the concept considered in this report, the post-ORC geothermal fluid will be used as a source of waste heat. This waste heat can be used for building space heating and domestic hot water as well as a source of heat for light industrial processes such as heating greenhouses, drying fruits and vegetables, and aquaculture systems. Significant investigation and design would be required to see how this heat could best be used.

To use this heat, it must be transported in a form that is accessible to customers. Generally, this can be done with a district heating network (DHN) where hot water (that is heated from the power plant waste heat through the heat exchanger shown in the diagram in Figure 2-2) is transported through insulated pipes to locations where customers can then transfer the heat to their heating systems through an energy transfer station (ETS). Existing building system retrofits may be required to be compatible with a DHN. New buildings can generally be designed to be compatible with limited cost or technical premium. The possibility of a DHN near the Clarke Lake area will be discussed further in Section 5.2.



All temperatures are approximate and are used as examples only.

Figure 2-2
Geothermal Binary Power Plant and District Heating Network Concept

2.1.3 Vendor Research – ORC Technology

Several global ORC technology providers were reviewed. At this level of analysis, the vendor research was focused on short-listing two manufacturers whose products best fit the scale of the proposed Clarke Lake project while being commercially available in Canada (supplier support) and having a proven track record of operation. From this review, this pre-feasibility study will consider the larger scale ORC options from Ormat and Turboden moving forwards. Exergy is another supplier of scalable ORC plant technology based out of Italy. We have not obtained additional information about their product.

2.1.3.1 Ormat Technologies Inc.

Ormat Technologies Inc. (Ormat), headquartered in Reno, Nevada, supplies the mechanical and electrical equipment for geothermal binary power plants packaged as the Ormat Energy Converter (OEC). The OEC is scalable with plant capacities ranging from 3.5 MW to 139 MW.

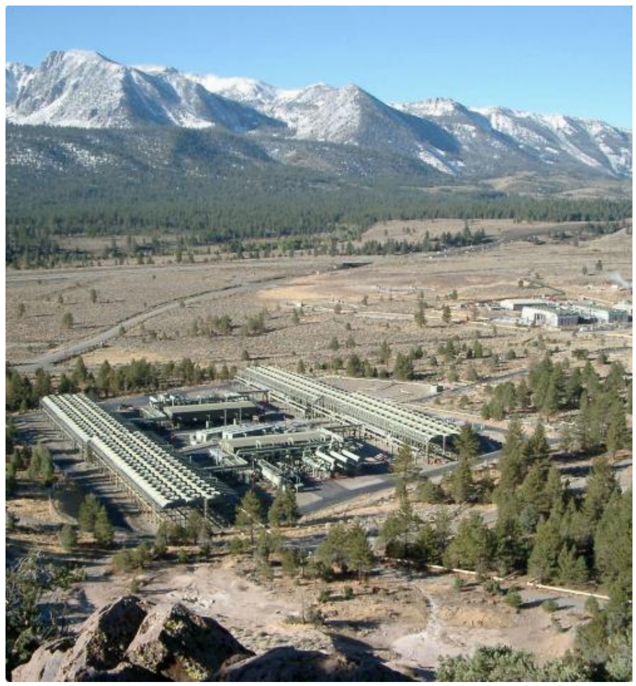


Figure 2-3
Ormat Mammoth Geothermal Complex (29 MW) near Mammoth Lakes, CA

Ormat also employs combined cycle technology that can use hot condensate from a geothermal flash power plant to power a secondary binary plant in a combined cycle, but for this feasibility study, the OEC as a binary power plant will be considered.

2.1.3.2 Turboden

Turboden, a Mitsubishi Heavy Industries group company, designs, manufactures, and maintains ORC systems and is based out of Italy. The technology is scalable with projects ranging from 0.4 MW to 16 MW in locations in Europe and North America.

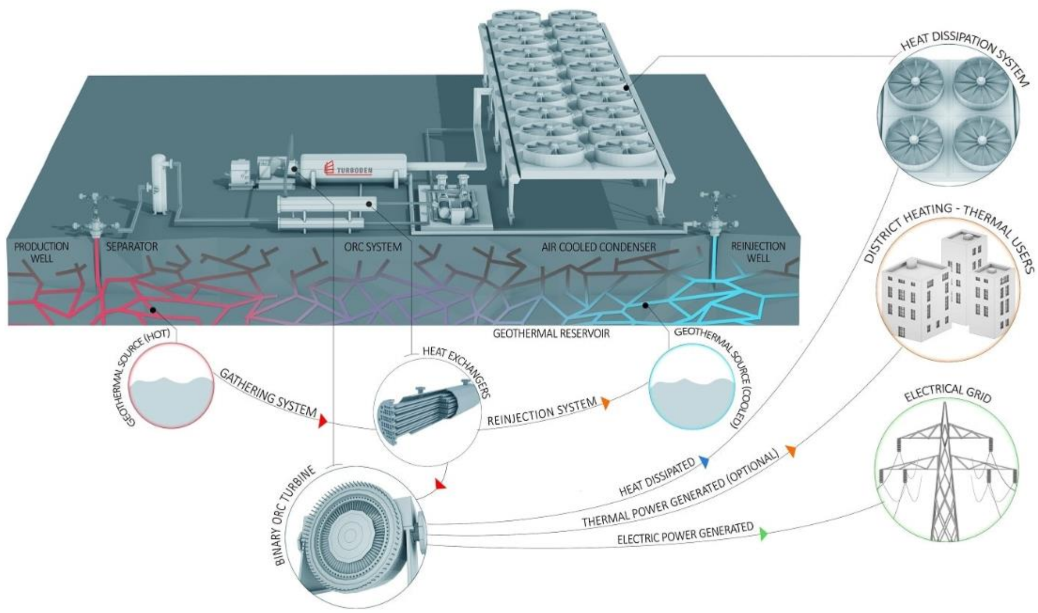


Figure 2-4
Turboden ORC Technology

2.1.3.3 Smaller ORC Technology Options

As mentioned above, while Ormat and Turboden's technology best meets the scale of the Clarke Lake project, there are smaller, more modular options available that are briefly described below:

- **ElectraTherm:** employs the ORC in modular 0.1 MW (110 kW) units called the ElectraTherm Power Generator.
- **Fuji Electric:** manufactures a modular 2 MW (2000 kW) ORC unit known as the Fuji Geothermal Binary System.
- **Pratt & Whiney:** produce another modular ORC unit known as the PureCycle Power System that delivers 0.28 MW (280 kW) of electrical energy.

While they may be suitable for smaller, pilot-scale plant development, they are unlikely to be an appropriate alternative to the larger ~15 kW systems that Ormat and Turboden offer due to complexity of numerous modules, and the lower overall efficiency that they offer. They are typically applied in industrial waste heat applications.

2.2 SITE LOCATION

As discussed in Section 1.3, Palmer-Wilson et al. produce a favourability map for geothermal development in the Western Canada Sedimentary Basin, and the Clarke Lake Reservoir area is highlighted as a region of higher favourability. Within the Clarke Lake Reservoir area, there are also areas of higher favourability as compared to other locations.

Palmer-Wilson et al. provided the favourability data to AE to further inform the favourability of a geothermal plant near the Clarke Lake Reservoir area. The data was filtered to show only the top 10% of the favourability scores, and the results are shown in Figure 1-2 above. It should be noted that it was not within AE’s scope to validate the favourability data from Palmer-Wilson et al.

The data shows that there are two distinct contours for areas that have top 10% favourability for a geothermal plant. One could presumably be built just west of the town of Muskwa and is shown as a green perimeter and labelled as Site A, while another option would be to build one further to the south-west and is labelled as Site B. Figure 1-2 also shows the 144 kV BC Hydro transmission line and its proximity to the sites, which will be further explored in Section 2.3 and 7.8.

At this stage, the assumed size of the geothermal plant is 13 hectares (not including the well field) based on estimates from measuring similarly sized Ormat plants in the United States (example: Ormat Brawley, 13 MW Binary (ORC) Plant, Imperial County, California). This could vary significantly and is only used for illustrative purposes at this point. The two options for site location will be further investigated in Section 3: Concept Site Development, and Section 4: Environmental Considerations, below.

2.3 POWER GRID INTERCONNECTION TECHNICAL REQUIREMENTS, LEGAL AND SALES FRAMEWORK

The electricity produced from this geothermal plant will have the possibility of being connected to the BC Hydro utility grid. The proximity of the transmission line to Sites A and B from Figure 1-2 is favourable and is discussed further in Section 7.8.

The traditional process for connecting to the grid for electricity sales to BC Hydro has been the BC Hydro Standing Offer Program (SOP) which is a process for the creation of a BC Hydro Electricity Purchasing Agreement (EPA) for projects with an electrical capacity of 100 kW to 15 MW. The Fort Nelson region, however, is not eligible for this program. Additionally, during the initiation of this pre-feasibility study, and at the time of this writing, the SOP has been indefinitely suspended since February 14, 2019 with no new applications being accepted or new EPAs, except for five First Nations clean energy projects.

It is noted that the existing electrical service in the Fort Nelson area is by a combination of carbon-intensive natural gas generation and electricity imports from Alberta which are also carbon-intensive. Offsetting this power generation with geothermal power could greatly reduce the GHG intensity of BC Hydro's power in this area. It is unknown if this is of interest to BC Hydro. Further, there is an interconnection with Alberta at this location, and may serve as an opportunity to sell low-carbon electricity to Alberta.

Although there is uncertainty in whether the SOP will be revived and whether this location would be eligible, this report will assume that the SOP can be accessed as a customer for geothermal electricity in BC, so a model plant with 15 MW will be developed as outlined in Palmer-Wilson et al., 2018.

A description of the SOP process as was valid prior to the SOP's suspension is described in the following sub-sections.

2.3.1 Pre-Application Meeting and Preliminary Assessment

Potential applicants to the SOP may request a meeting or conference call with BC Hydro at any time prior to applying. The purpose of the pre-application meeting is to review the application process, the Standard Form EPA, the interconnection requirements and study costs, First Nations consultation requirements, and other matters required to facilitate the application process.

2.3.2 Submitting and Application to the SOP

To apply for the SOP, the developer must submit the following:

- A completed and signed SOP Application Form with appropriate exhibits. The exhibits include, but are not limited to:
  - Project Description and Schedule
  - Minister's Letter of Confirmation
  - EcoLogo Letter of Opinion
  - Greenhouse gas plan for the project
  - Copy of ESA for a Project Behind a Customer Load
  - Copy of EPA with BC Hydro
  - Load Displacement or Demand Side Management Agreements
  - Permits, site control, zoning approvals and supplementary consultation information
  - Information about limited partnership, general partnership, joint venture or other entity
  - Proposed project-specific changes to the standard form EPA (with rationale)
  - Disclosure under BC Hydro Code of Conduct Guidelines
  - Optional: Application for System Impact Study (see Section 0). This could also wait until after the review.
  - The Confidentiality and Compliance Agreement signed by the developer (if not previously submitted with a pre-application meeting request) in two (2) hard copies.

2.3.3 Review and EPA Process

On the path to producing an EPA, BC Hydro will complete the following tasks:

- Application Review: Completeness and Eligibility
- Review of System Impact Study: After the application review, the Developer is requested to begin a System Impact Study and pay the associated fees. Upon completion of the study, BC Hydro will review it to determine whether BC Hydro is ready to support the project's interconnection to the relevant system. Note: An application for the System Impact Study can also be included with the general application.
- EPA Preparation: Review of any project specific EPA changes requested by the Developer in the application. Upon review, there is an opportunity to submit a Statement of Project Changes prior to a final draft EPA being produced.
- EPA Offer and Acceptance: BC Hydro will send the Developer either an offer of an EPA or a notice of rejection of the Application.

2.3.4 Due Diligence and Consultation

BC Hydro may, but is not required to, undertake any investigation or inquiries and/or undertake any consultation with any governmental or regulatory authority or any other person or group as BC Hydro considers necessary in its discretion with respect to a developer, a project, and/or an application and may, in reviewing an application, consider any information received as a result of such investigation, inquiry and/or consultation.

2.3.5 Rejecting Applications

BC Hydro may accept or reject any application and may decide to offer or not to offer a Project EPA to a developer at its discretion. BC Hydro may reject an application at any stage in the application review process notwithstanding any prior decision by BC Hydro in the application review process or prior completion of any step in the application review process.

The SOP application would typically be submitted following the preliminary design phase. As such, if the program is reinitiated, the pre-application meeting should be arranged at the earliest convenience.

The revenue estimate associated with using the BC Hydro SOP will be covered in Section 5.1.1.

3 Concept Plant Site Development

The purpose of this section is to describe the scope of typical civil construction work and associated estimated costs that would potentially be required to construct the potential 15 MW geothermal power plant at the two possible locations south-west of Fort Nelson, British Columbia (Site A and Site B). Due to the absence of geotechnical information and the high-level nature of this study, the cost estimate will be "Class D" which has an intended accuracy of ± 50%.

Site A is situated close to an industrial area near the town of Muskwa, 1 km west of the Alaska Highway (Highway 97), on land which appears to have been partially developed and cleared of vegetation. Site A is intended to illustrate the requirements for site development in a partially developed location. Site B is situated south-west of Muskwa in a forested area 1.6 km west of the Alaska Highway. The locations and assumed plant outlines (estimated at 13 hectares from a binary geothermal plant of similar capacity in the United States – Ormat Brawley, Imperial County, California) of Site A and B are shown in Figure 3-1. Note that the conceptual Site B location is at the edge of the Site B contour in Figure 1-2 to locate it next to Rodeo Rd. This location illustrates the development requirements of a forested area, which part of the rationale of the Site B concept. The size and shape are purely speculative at this point and will need to be studied and developed further for higher accuracy. The choice of 13 hectares is used for illustration only and to convey the understanding of constraints and development requirements. Each site will require a different level of effort for construction based on the existing site conditions and its respective proximity to existing infrastructure.

In the sections below, we provide a description of our assumptions and methods of evaluation, the typical civil construction tasks, and Class D cost estimates for each site, which will be used in conjunction with other plant costs in Section 7. The costs are derived from historical unit and lump sum rates for similar projects.

3.1 ASSUMPTIONS

The assumptions related to the scope of civil construction work and associated costs are summarized below:

- The assessment of the sites has been undertaken by desktop study only and therefore the information available is based on previous reports and google earth imagery.
- Both geothermal plant sites are assumed to cover an area of 13 hectares which is an area estimated from a survey of binary geothermal plants of similar capacity in the United States (Example: Ormat Brawley, Imperial County, California).
- No geotechnical investigation information is available for either site.
- Reviewing the proposed site locations using Google Earth, Site A appears to be partially developed and Site B appears to be completely undeveloped. Based on this we have assumed:
    - Stripping, clearing, and grubbing will be required for approximately 50% of Site A and 100% of Site B
    - 1 m uniform depth of fill material will be required over 50% of Site A and 100% of Site B.
- Stripping depth is assumed to be 300 mm.

- 300 mm granular base material is required across both sites. It is noted that this could change significantly based on the results of geotechnical investigations.
- Based on our review of the site access road conditions using Google Earth, it appears access road improvements are not required for Site A. Site B can be accessed directly from Rodeo Road and will require no access road upgrades.
- Utility connections are not included in the cost estimate.
- Plant sewage system not included as part of this cost estimate.
- Fencing is required around the 2.35 km geothermal plant perimeter.

3.2 SCOPE OF CIVIL CONSTRUCTION & CLASS D COST ESTIMATE BASIS

Clearing & Grubbing

Clearing refers to the removal and disposal of standing and fallen trees, stumps, logs, upturned roots, rotten wood, all other vegetation growth, accumulations of rubbish, and any other objectionable material. All material, slash, and debris resulting from clearing operations is typically disposed of by burning, burying, chipping and distributing, or salvaging material for re-selling.

Grubbing is the entire removal and disposal of all stumps, roots and embedded logs below the ground line. Grubbing is typically carried out over the same area as is required for clearing. We have assumed clearing & grubbing is required for 50% of Site A (6.5 Hectare), and 100% of Site B (13 Hectare).

Typical clearing and grubbing unit prices are shown in Table 3-1.

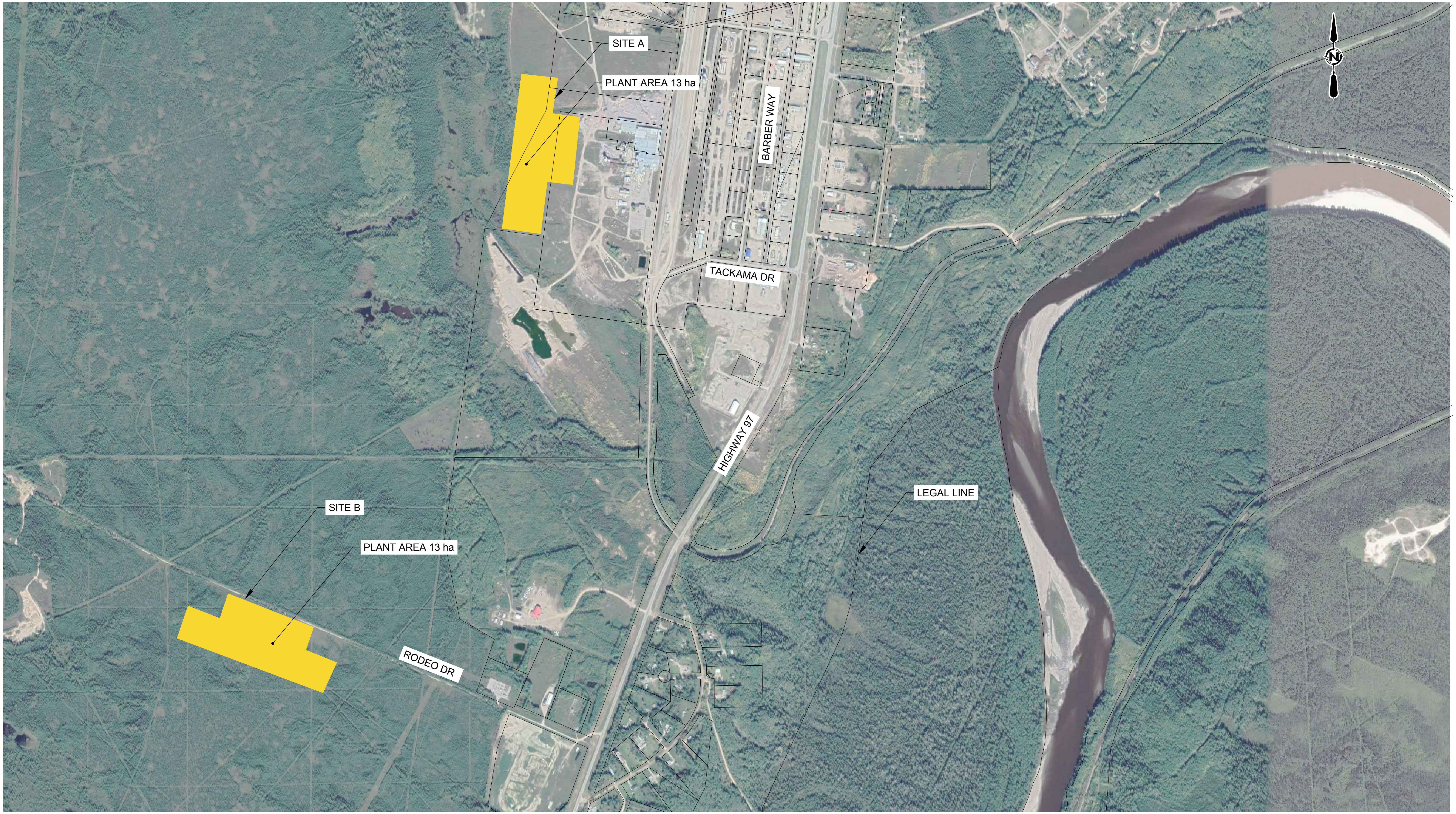
Table 3-1
Rates for Clearing & Grubbing based on Historical Prices

Description of Work	Cost ($)	Unit
Clearing	5,000	Hectare
Grubbing	7,000	Hectare

Stripping

The uppermost layers of soils are made up of organics capable of supporting vegetation and other materials unsuitable for re-use in embankment construction. For this reason, the layer is stripped and stockpiled somewhere that it can be properly drained and remain free of spoil and invasive plants to allow for re-use post construction. Stripping depth is usually estimated once the geotechnical investigation is carried out, in this case we will assume 300 mm over the full disturbed area of the sites which equates to 19,500 m^3 of stripping material for Site A, and 39,000 m^3 for Site B. Historical unit rates from previous projects have been used for estimating the cost of topsoil stripping, our cost assumption is shown in Table 3-2.

IF NOT 25 mm ADJUST SCALES
25 mm
SCALE(S) SHOWN ARE INTENDED FOR TABLOID (11X17) SIZE DRAWINGS UNLESS NOTED OTHERWISE



PLOT DATE: 12/14/2018 1:21:50 PM
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AE PROJECT No.	2018-2262
SCALE	NTS
APPROVED	
DATE	20181214
REV	A
DESCRIPTION	ISSUED FOR INFORMATION

FIGURE 3-1

GEOSCIENCE BC

CLARKE LAKE
GEOTHERMAL PLANT LOCATIONS

Table 3-2
Historical Rates for Stripping

Description of Work	Cost ($)	Unit
Stripping	6	m^3

Earthworks & Grading

Depending on the existing terrain at each site, excavation and grading may be required to create a level foundation suitable for construction and which will support the anticipated design loads. Excavation may be required to allow for adequate drainage of the site, formation of the plant platform foundation, and profiling of slopes.

We have assumed that fill material will be imported for site grading and the construction of a suitable platform foundation structure. The plant platform typically consists of compacted layers of granular material above a prepared subgrade. The depth and material characteristics are typically defined by a geotechnical engineer after a geotechnical investigation has been conducted. For this study we have assumed 1 m of imported fill material is required over 50% of Site A and 100% of Site B, with a 300 mm granular base layer above 100% of both sites.

We used historical unit rates from previous similarly located infrastructure projects (i.e.: Yukon) to estimate the unit cost for granular and fill material, shown in Table 3-3. The costs will vary depending on the material source and associated haul distances.

Table 3-3
Historical Rates for Fill

Description of Work	Cost ($)	Unit
Fill Material	20	m^3
Granular Material	50	m^3

Site Access Roads

Each site requires an access road which has suitable width and structural capacity to support construction traffic and future traffic volumes. Based on our Google Earth review, it appears that the industrial area at Site A has several existing access route options to link the Site to the nearby Alaska Highway. Site B can be accessed from Rodeo Road which connects directly to the Alaska Highway. As such, we have assumed that the existing access roads can be utilized at Site A & B and no upgrades are currently required.

Stormwater Drainage

Each geothermal site will have a storm water drainage system to allow for surface runoff to be discharged from site, Surface runoff can be managed through site grading, ditching, underground storm sewers and/or settlement ponds. The appropriate storm water management system will be determined during the later design stages of the project. For cost estimating purposes, we have assumed a drainage ditch around the 2.35 km perimeter of the site. A cost of $50 per linear meter has been estimated from a lower mainland Ministry of Transportation and Infrastructure (MOTI) project historical unit rate from 2018 for Type-D cut material for off-site disposal with an added contingency due to the rural nature of the sites compared to the Lower Mainland. This is shown in Table 3-4.

Table 3-4
Historical Rates for Drainage

Description of Work	Drainage Cost	Unit
Drainage	50	Linear Metre

Utility Connections

Utility connections are part of the civil construction scope of works, and the extent of work will vary based on distance from existing infrastructure. It is assumed the following utilities will be required for both sites.

- Power – connection to local electricity grid.
- Sanitary – sewage outlet connection, storage tank, or septic field.
- Potable water – clean water source required, municipal infrastructure, well, or rainwater harvesting.
- Communications – could be included with power line.
- Natural gas – could be included as a backup.

Due to the uncertainty of existing utility infrastructure locations and costs set by utility providers, utility connection costs are not included in this study.

Fencing

Fencing is required around the 2.35 km geothermal plant perimeter. We have assumed a Type D Standard Height (1.8 m) Chain Link Fence (BC MoTI Standard Specifications for Highway Construction Drawing SP741-05.01) will be used for perimeter fencing at each site. Historical unit rates to supply and install chain link fence were used to estimate the unit cost summarized in Table 3-5.

Table 3-5
Historical Rates for Fencing

Description of Work	Cost	Unit
Fencing	160	Linear Metre

Overall Site Cost Estimates

The combined cost for civil construction tasks required for each site is summarized in Section 7.2.

4 Environmental Considerations

The purpose of this section is to describe environmental features and potential constraints associated with the construction of a 15 MW geothermal power plant at two possible sites (Sites A and B) located southwest of Fort Nelson near the town of Muskwa, British Columbia. This section describes our methodology and findings and provides a preliminary summary of the main environmental constraints and regulatory requirements associated with construction at the two site options.

4.1 METHODOLOGY

A desktop review was conducted on background information to identify environmental features present, or potentially present, within the two sites and key environmental constraints. The focus of this review included fish and fish habitat, wildlife and wildlife habitat, and species at risk. The information reviewed included:

- GoogleEarth© online imagery;
- BC Conservation Data Centre[1] database for rare and endangered element occurrences of wildlife and vegetation;
- BC Habitat Wizard[2] for known occurrences of invasive species, watercourses, or fish presence;
- Fisheries Information Summary System;[3]
- Species at Risk Public Registry[4] to determine status of element occurrences of species at risk;
- Northern Rockies Regional Municipality Official Community Plan (OCP)[5] for land use mapping;
- Vegetation Resources Inventory (VRI)[6] for land cover mapping; and
- Freshwater Atlas[7] for watercourse mapping (adjusted to aerial imagery).

In addition, a Site Registry search was conducted for each of Sites A and B. The Site Registry search included a small area search for records within a 500 m radius of Site A and Site B. The small area search returned no records for the sites or neighbouring properties within 500 m.

[1] BC Conservation Data Centre. 2019. BC Species and Ecosystems Explorer. Available at: http://a100.gov.bc.ca/pub/eswp/search.do?method=reset. Accessed March 2019.
[2] British Columbia Ministry of Environment and Climate Change Strategy. 2019. Habitat Wizard database. Available at: www.env.gov.bc.ca/habwiz. Accessed March 2019.
[3] British Columbia Ministry of Environment and Climate Change Strategy. 2019. Fisheries Information Summary System. Available at: http://www.env.gov.bc.ca/fish/fiss/. Accessed March 2019.
[4] Species at Risk Public Registry. 2019. Available at: https://www.canada.ca/en/environment-climate-change/services/species-risk-public-registry.html. Accessed March 2019.
[5] Northern Rockies Regional Municipality. 2011. Official Community Plan Bylaw No. 64. Available at: https://nr.civicweb.net/document/59371. Accessed March 2019.
[6] Government of British Columbia. 2011. Vegetation Resource Inventory. Available at: https://catalogue.data.gov.bc.ca/dataset/vri-forest-vegetation-composite-polygons-and-rank-1-layer. Accessed March 2019.
[7] Integrated Land Management Bureau. 2019. Freshwater Atlas. Available at: https://www2.gov.bc.ca/gov/content/data/geographic-data-services/topographic-data/freshwater Accessed March 2019

4.1.1 Constraints/Options Analysis

Constraints for Sites A and B were organized by environmental feature (i.e. fish and fish habitat, wildlife and wildlife habitat [vegetation and birds, amphibians, and mammals], and species at risk). The level of constraint was rated as low when best practices apply, medium when the constraint can be mitigated but likely involves regulatory approvals, and high when impacts cannot be mitigated and have a likelihood of requiring offsetting.

The preferred site option was chosen by the lowest rating. When ratings were equal, the option with a smaller footprint impact to habitat was chosen.

4.2 KEY ENVIRONMENTAL FEATURES

4.2.1 Land Use and Zoning

4.2.1.1 Current Land Use

The sites fall within the Northern Rockies Regional Municipality (NRRM). According to the NRRM OCP[5], part of Site A is zoned for Heavy Industrial and part for Resource Conservation. It is surrounded by Heavy Industrial use on the east side[8] and by Resource Conservation on the west side. Site B is zoned for Resource Conservation use (completely surrounded by Resource Conservation use) (Figure 4-1). Heavy Industrial areas are encouraged to infill vacant industrial land and restrict Heavy Industrial expansion near the Muskwa River. Resource Conservation areas are intended to preserve wilderness and protect local wildlife while balancing local recreation, forestry, agriculture, and mineral/aggregate extraction uses. The OCP does not identify any Natural Hazard or Environmentally Sensitivity Areas (ESAs) within 100 m of either site. Neither site is located within the Agricultural Land Reserve[9].

4.2.1.2 Previous Land Use

Based on a preliminary assessment, the industrial portion directly east of Site A could potentially be a concern for contamination at the site. There are no potential sources of contamination (i.e., industrial operations, waste management, fuel storage or dispensing operations) at Site B or surrounding properties. However, a formal contaminated sites assessment (i.e., a Phase I ESA) would be required for both sites to confirm the potential that soil, groundwater, or vapour at the site is contaminated relative to applicable standards under current or intended land use. The assessment should be conducted in general accordance with the requirements of the BC Contaminated Sites Regulation (CSR)[10] of the *Environmental Management Act* and general protocols outlined in Z768-01 (R2016) – Phase I Environmental Site Assessment Standards[11].

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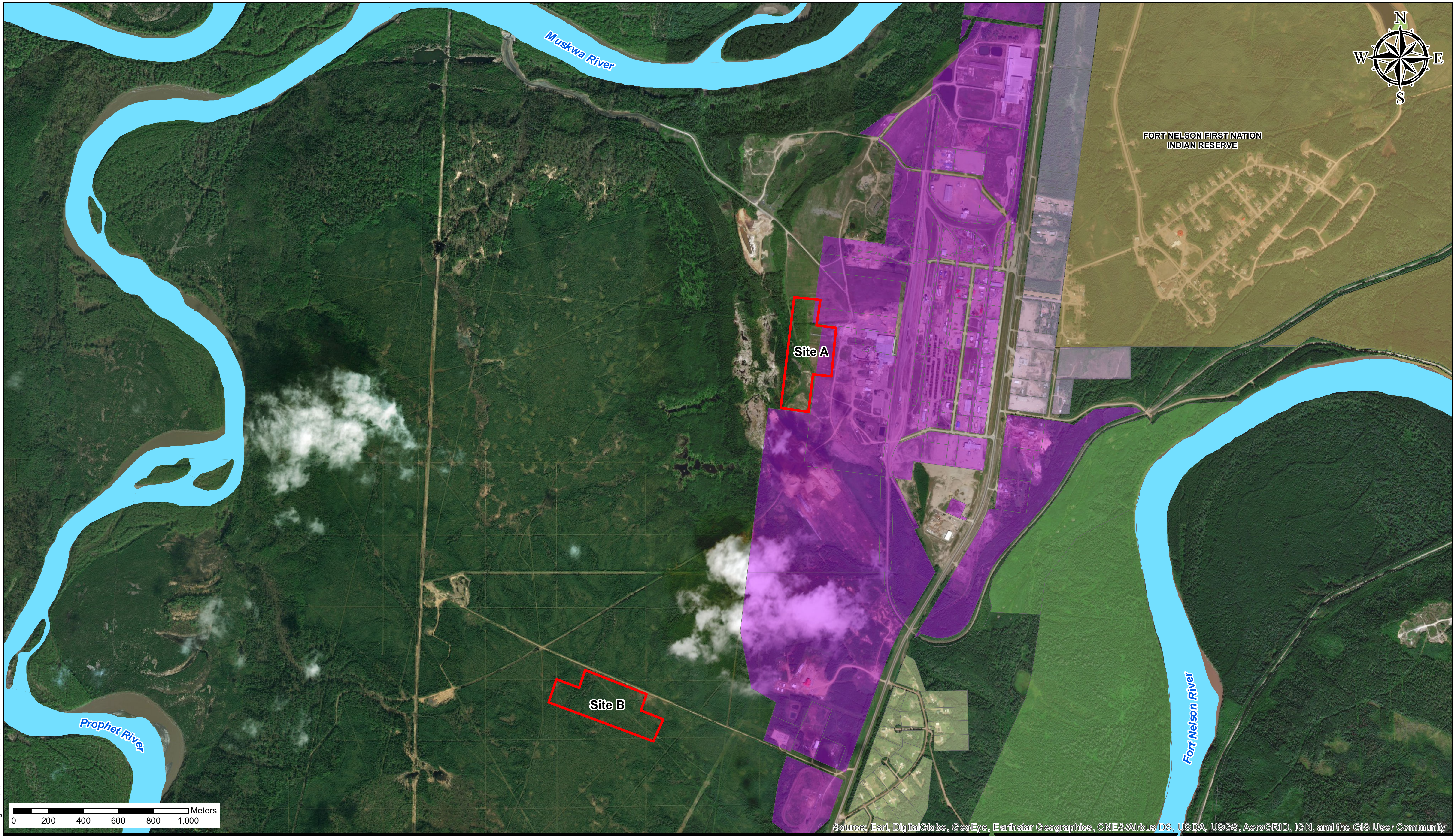
[8] The industrial property directly west of Site A is a former plywood mill.

[9] Agricultural Land Commission. 2019. ALR Property and Map Finder Application. Available at: https://catalogue.data.gov.bc.ca/dataset/alr-property-and-map-finder/resource/1a06e8e3-2b9c-406c-b7ae-43d7172aed84. Accessed March 2019.

[10] Contaminated Sites Regulation. B.C. Reg. 375/96. Including amendments up to B.C. Reg. 253/2016, October 27, 2016. Victoria, BC.

[11] Canadian Standards Association. 2016. Z768-01 (R2016) – Phase I Environmental Site Assessment.



Associated Engineering

Zoning

Heavy Industrial	Light Industrial
Large Holdings Agriculture	Rural Residential
Parcel boundary	First Nations reserve

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DATE: March 2019
DRAWN BY: BdJ

FIGURE 4-1: SITE A AND B ZONING

GeoScience BC
Clarke Lake
Geothermal Plant Locations

4.2.2 Fish and Fish Habitat

Three major fish-bearing rivers are located in proximity to the sites: Muskwa River, Prophet River, and Fort Nelson River (Figure 4-1). The tributaries (all first or second order streams) to these rivers are potentially fish-bearing as there are no documented barriers or obstacles to fish passage[12]. If not fish-bearing, these rivers are, at minimum, a valuable source of food and nutrient supply to downstream fish habitat (Figure 4-2). There is no available information on the biophysical characteristics of the tributary to Muskwa River[13] nor the tributary to the Fort Nelson River[14]. The tributary to the Prophet River[15] is a low-gradient (0.5%) stream with an average channel width of 1.4 m[16]. The NRRM does not have established riparian setbacks for any of the tributaries; therefore, the default 30 m wide riparian strip on either side of the tributaries applies in accordance with the Riparian Areas Regulation[17,18]. In addition, based on available mapping, Site A and Site B are located within (at least partially) wetland habitat. Although these locations being partially within wetlands are not ideal, the environmental consequences of this location choice will be explored as a worst-case scenario in terms of permitting and construction and the likelihood of an environmental assessment being required.

The Muskwa and Prophet Rivers flow north into the Fort Nelson River which also flows north. Documented fish species in these rivers within 3 km of the sites include mountain whitefish (*Prosopium williamsoni*), white sucker (*Catostomus commersonii*), troutperch (*Percopsis omiscomaycus*), flathead chub (*Platygobio gracilis*), longnose sucker (*Catostomus catostomus*), longnose dace (*Rhinichthys cataractae*), finescale dace (*Phoxinus neogaeus*), spoonhead sculpin (*Cottus ricei*), Dolly Varden (*Salvelinus malma*), burbot (*Lota lota*), Arctic grayling (*Thymallus arcticus*), lake chub (*Couesius plumbeus*), and inconnu (*Stenodus leucichthys*)[2].

Based on the two site options (i.e., Site A and Site B), we understand that Project work requires vegetation removal and earthworks (e.g., potential infilling of wetlands). These works will result in the loss of riparian vegetation and potentially aquatic habitat due to instream works (i.e., work below the high-water mark of a tributary or within wetland habitat). As such, the following mitigation measures should be implemented to avoid, minimize, and mitigate potential impacts of the Project on fish and fish habitat:

- Avoid instream work (i.e., work below the high-water mark of a tributary or within wetland habitat) to the extent possible.
- Minimize the total permanent footprint in riparian areas.

[12] Site A is 126 m from a tributary to the Muskwa River. Site B is situated in the headwaters of a tributary to the Prophet River and approximately 148 m from a tributary to the Fort Nelson River.
[13] Watershed Code: 212-580800-04300, Waterbody ID: 00000LMUS
[14] Watershed Code: 212-649800, Waterbody ID: 00000MFRT
[15] Watershed Code: 212-580800-04700-01400, Waterbody ID: 00000LPRO
[16] British Columbia Ministry of Environment and Climate Change Strategy. 2019. Habitat Wizard database. Available at: www.env.gov.bc.ca/habwiz. Accessed March 2019.
[17] Riparian Areas Regulation, B.C. Reg. 376/2004. Available at: http://www.bclaws.ca/civix/document/id/complete/statreg/376_2004.
[18] Although the Riparian Areas Regulation does not apply within the Peace Region, it was referenced as a provincial standard methodology for assessing riparian setbacks.

- Conduct unavoidable instream works within the applicable reduced risk work window (July 15 - August 15)[19]; and
- Develop a Construction Environmental Management Plan (CEMP) that includes site-specific mitigation measures to protect fish and fish habitat prior to construction.

Based on our understanding of the proposed Project works, we anticipate the Project will require the following environmental approvals once a final design option has been determined:

- A Notification or Change Approval application (Section 4.3) to the BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNR) for changes in and about a stream (i.e., potential infilling of wetland habitat and/or stream) in accordance with the provincial *Water Sustainability Act*; and
- A request for project review to Fisheries and Oceans Canada (DFO) for the potential infilling of a stream (i.e., permanent alteration or destruction of fish habitat) in accordance with the federal *Fisheries Act*. Depending on the Project impacts to fish and fish habitat, an application for Authorization under the *Fisheries Act* may be required, including an offset plan to compensate for potential Project related impacts.
- Collection permits from FLNR and DFO may be required to conduct pre-construction salvages, if the tributaries and other aquatic habitat potential impacted are found to be fish-bearing.

4.2.3 Wildlife and Wildlife Habitat

The sites are located within the Boreal White and Black Spruce (BWBS) biogeoclimatic zone. Typical vegetation in this zone includes black cottonwood (*Populus trichocarpa*), white spruce (*Picea glauca*), trembling aspen (*Populus tremuloides*), alder (*Alnus* sp.), and paper birch (*Betula papyrifera*) in the overstorey; willow (Salix sp.), red-oisier dogwood (*Cornus stolonifera*), and prickly rose (*Rosa acicularis*) in the understorey; with bracken fern (*Pteridium* sp.), Canada goldenrod (*Solidago canadensis*), horsetail (*Equisetum* sp.), trailing raspberry (*Rubus pubescens*), twinflower (*Linnaea borealis*), and wild strawberry (*Fragaria vesca*) as groundcover[20][21]. There is visual evidence of previous anthropomorphic disturbance at Site A, which is mainly cleared for industrial use, and there is some localized pipeline disturbance and clearing at Site B. Invasive species such as caraway (*Carum cavi*), sowthistle (*Soncus* sp.), common tansy (*Tanacetum vulgare*), oxeye daisy (*Leucanthemum vulgare*), and scentless camomile (*Matricaria perforate*) have been observed nearby (i.e. along Highway 97)[22].

Both sites contain some forested area. The forested areas likely include muskeg (hence VRI mapping indicating wetlands within) and provide habitat for invertebrates, amphibians, mammals, songbirds and

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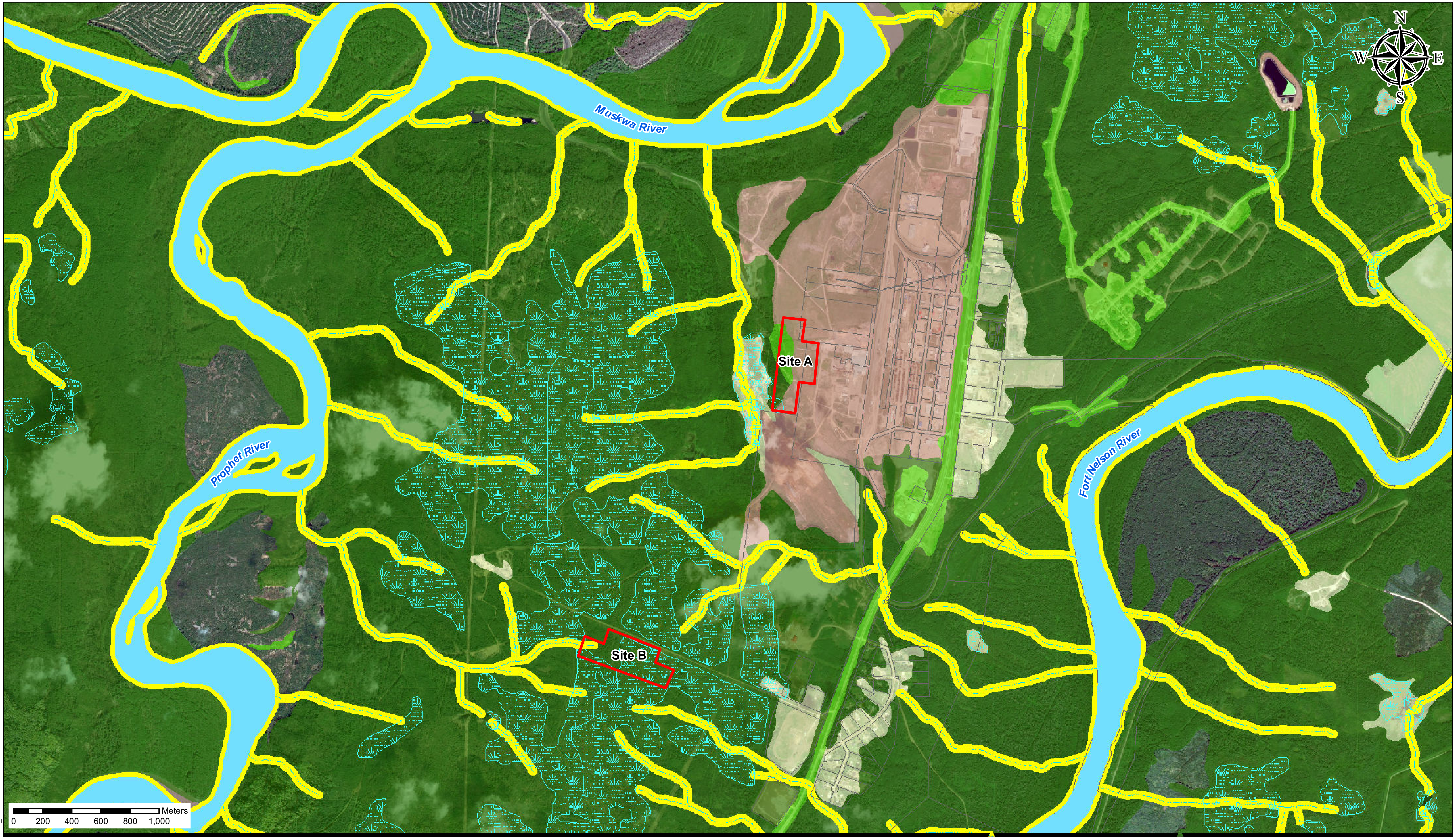
[19] Ministry of Forests, Lands, and Natural Resource Operations. N.d. Regional timing windows. Available at: https://www2.gov.bc.ca/gov/content/environment/air-land-water/water/water-licensing-rights/working-around-water/regional-terms-conditions-timing-windows. Accessed March 2019.
[20] DeLong, C., Annas, R.M., and Stewart, A.C. 1991. Ecosystems of Canada: Chapter 16 Boreal White and Black Spruce Zone. Available at: https://www.for.gov.bc.ca/hfd/pubs/docs/srs/srs06/chap16.pdf Accessed March 2019.
[21] Dillon Consultants Ltd. 2013. Fortis BC - Muskwa River Crossing Project, Preliminary Environmental and Socioeconomic Assessment.
[22] British Columbia Ministry of Environment and Climate Change Strategy. 2019. Habitat Wizard database. Available at: www.env.gov.bc.ca/habwiz. Accessed March 2019.



Associated Engineering

Parcel boundary
Watercourse riparian area setback
River
Stream - definite
Stream - intermittent
Flow Connectors - Inferred
Wetlands
Land Cover (VRI)
Gravel Pit
Herbs
Shrubs
Forest
Urban

PROJECT NO.:	2018-2262.000.005
DATE:	March 2019
DRAWN BY:	BdJ

FIGURE 4-2: SITE A AND B LOCATIONS AND ENVIRONMENTAL FEATURES

GeoScience BC

Clarke Lake
Geothermal Plant Locations

raptors. The riparian areas likely provide forage habitat and staging and stopover migration areas for a variety of mammal and bird species. Based on historical surveys, the forested areas of the Muskwa valley provide habitat for large and small mammals (e.g., black bear [*Ursus americanus*], deer [*Odocoileus virginianus and O. hemionus*], fox [*Vulpes vulpes*], lynx [*Lynx canadensis*], moose [*A. alces anderso*ni], deer mouse [*Peromyscus*]) and songbirds (e.g., common raven [*Corvus corax*], hairy woodpecker [*Leuconotopicus villosus*], black-capped chickadee [*Poecile atricapillus*], red-tailed hawk [*Buteo jamaicensis*], and red-eyed vireo [*Vireo olivaceus*])[18]. Site A backs onto an herbaceous wetland (based on VRI mapping and aerial imagery). Wetlands generally have a higher level of biodiversity and wildlife usage (e.g., songbirds, waterfowl, amphibians) than other habitats.

We understand that Project works will include vegetation removal and earthworks. These works will result in the loss of wildlife habitat associated with riparian, wetland, and forested areas. As such, the following mitigation measures should be implemented to avoid, minimize, and mitigate potential impacts on wildlife and wildlife habitat:

- Prior to construction, conduct ground surveys for vegetation, nests, and wildlife.
- Minimize work in wetland areas, which are environmentally sensitive (i.e., higher wildlife use and at risk of erosion and sedimentation issues associated with infilling).
- Minimize native vegetation removal, as forests have a higher likelihood of wildlife use (e.g., raptor nesting) than previously disturbed areas. Remove invasive vegetation where possible.
- Avoid vegetation removal (e.g., tree felling, grubbing, stump removal, land clearing etc.) during the regional bird nesting period (May 6 to August 10)[23]. If working outside the period is not possible and vegetation clearing is required, a Qualified Environmental Professional (QEP) should conduct pre-clearing bird nest surveys to identify, and thereby avoid, any active nesting in an area. Under the *Wildlife Act* (R.S.B.C. 1996, c. 488), occupied nests of any bird species and raptor nests (whether active or not) are protected year-round.
- If raptor nests are observed, protect nests year-round (whether or not in use). If loss of nest trees is unavoidable, approval to move the nests into a replacement structure will be required. Tree felling should occur outside the nesting season for the species.
- Revegetate cleared areas with native tree and shrub species, where possible. As soils in the project area are very sandy, cleared slopes should be hydroseeded with a certified weed-free seed mix appropriate to local climate conditions as soon as feasible to assist in preventing the spread of invasive plant species and minimize the potential for erosion. Ensure that seed mixes do not contain weeds or invasive species.

Based on our understanding of the current proposed works, the Project may require a General Wildlife Permit (including BC Animal Care form) from MFLNRO for conducting wildlife salvages if they are required based on wildlife surveys.

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[23] Government of Canada. 2019. General nesting periods of migratory birds. Available at: https://www.canada.ca/en/environment-climate-change/services/avoiding-harm-migratory-birds/general-nesting-periods.html . Accessed March 2019.

4.2.4 Species at Risk

There is the potential for 26 species at risk within the two sites including five plant, four insect, ten bird, and seven mammal species (Table 4-1)[24]. The BC Conservation Data Centre (CDC) maintains records of marked known occurrences (MKOs) of rare and endangered vertebrates, invertebrates, plants, and ecosystems in the province[25]. These records are individual, verified occurrences of species and ecosystems that the CDC has mapped. Two of the 26 potential species at risk have MKOs within 5 km of the sites (Table 4-1), but there are MKOs of species at risk within 4 km of the sites. No mapped critical habitat occurs within 5 km of the sites; however, most species have associations with the forested muskeg and wetland habitats present at both sites (Table 4-1). Caribou are generally present at low density and there is a viable grizzly population that overlaps both sites.

The project work requires vegetation removal and earthworks. These works will result in the loss of forest and riparian vegetation and likely wetland habitat. As such, the following mitigation measures, at minimum, should be implemented to avoid, minimize, and mitigate impacts on species at risk:

- Follow mitigation measures and best practices for wildlife outlined in Section 4.2.3 including conducting ground surveys for vegetation, wetland type, nests, and wildlife to confirm species at risk presence or absence.
- Minimize work in wetland areas, which have higher potential for species at risk.

4.3 SITE SPECIFIC

Once the design team has chosen a preferred site option, a detailed Environmental Assessment (EA) including a site visit to confirm vegetation and wildlife usage should be completed to determine permanent and temporary footprint impacts and associated mitigation measures (or offsetting recommendations). Areas of potential impact provided below are only estimates based on the potential locations identified and should be revised and updated once the detailed designs have been produced. The estimates are used below as an indicator to evaluate the relative level of impacts and potential constraints of each option. The detailed EA report would be included in the regulatory permitting submissions, if applicable.

As details of pipeline construction are unknown, environmental constraints associated with this construction were assumed to be similar for both options and are omitted from this options analysis. Based on our analysis of the two site options, a summary of the options is provided below.

4.3.1 Site A

Approximately 2.5 ha (20%) of Site A is currently zoned for Heavy Industrial use (aligns with OCP objectives), and the remainder of the site (approximately 10.5 ha) would require rezoning to Heavy Industrial expansion. Based on a preliminary assessment, the industrial portion directly east of Site A could

[24] BC Conservation Data Centre. 2019. BC Species and Ecosystems Explorer. Available at: http://a100.gov.bc.ca/pub/eswp/search.do?method=reset. Accessed March 2019.
[25] British Columbia Ministry of Environment and Climate Change Strategy. 2019. Habitat Wizard database. Available at: www.env.gov.bc.ca/habwiz. Accessed March 2019.

Table 4-1
Potential Species at Risk within the Sites and Documented Occurrences Within 5km

Class	Scientific Name	English Name	BC List	Prov Status	SARA	COSEWIC	MKO w/in 5 km?	Habitat Subtype
Plants	*Carex lapponica*	Lapland sedge	Red	S1	-	-	N	Bog;Fen;Conifer Forest - Moist/wet
	Oxytropis campestris var. *davisii*	Davis' locoweed	Blue	S3	-	-	N	Rock/Sparsely Vegetated Rock;Tundra;Conifer Forest - Moist/wet;Gravel Bar
	Penstemon gormanii	Gorman's penstemon	Blue	S2S3	-	-	N	Riparian Shrub;Cliff;Rock/Sparsely Vegetated Rock;Talus;Sand Dune;Riparian Herbaceous
	Salix petiolaris	meadow willow	Blue	S3	-	-	N	Bog;Meadow;Deciduous/Broadleaf Forest;Beach;Riparian Herbaceous
	Salix raupii	Raup's willow	Red	S2	-	-	N	Bog;Riparian Shrub;Stream/River;Mixed Forest (deciduous/coniferous mix)
Insects	*Calopteryx aequabilis*	River Jewelwing	Blue	S3	-	-	N	Riparian Forest;Riparian Shrub;Stream/River
	Lycaena hyllus	Bronze Copper	Blue	S3	-	-	N	Fen;Swamp;Marsh;Riparian Forest;Riparian Shrub;Riparian Herbaceous;Gravel Bar
	Phyciodes batesii	Tawny Crescent	Blue	S3	-	-	N	Meadow;Grassland;Shrub - Natural;Deciduous/Broadleaf Forest
	Somatochlora kennedyi	Kennedy's Emerald	Blue	S3S4	-	-	N	Bog;Fen;Marsh;Riparian Shrub
Birds	*Buteo platypterus*	Broad-winged Hawk	Blue	S3?B	-	-	N	Swamp;Marsh;Riparian Forest;Riparian Shrub;Meadow;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix)
	Cardellina canadensis	Canada Warbler	Blue	S3S4B	1-T (Feb 2010)	T (Mar 2008)	**Y**	Riparian Forest;Shrub - Natural;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Shrub - Logged
	Contopus cooperi	Olive-sided Flycatcher	Blue	S3S4B	1-T (Feb 2010)	SC (May 2018)	N	Bog;Fen;Swamp;Riparian Forest;Conifer Forest - Mesic (average);Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Pond/Open Water
	Euphagus carolinus	Rusty Blackbird	Blue	S3S4B	1-SC (Mar 2009)	SC (Apr 2017)	N	Bog;Fen;Swamp;Marsh;Lake;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Urban/Suburban;Pond/Open Water;Industrial
	Hirundo rustica	Barn Swallow	Blue	S3S4B	1-T (Nov 2017)	T (May 2011)	N	Estuary;Bog;Fen;Swamp;Marsh;Riparian Forest;Riparian Shrub;Stream/River;Lake;Pasture/Old Field;Cultivated Field;Hedgerow;Meadow;Grassland;Shrub - Natural;Sagebrush Steppe;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Urban/Suburban;Pond/Open
	Melanitta perspicillata	Surf Scoter	Blue	S3B,S4N	-	-	N	Riparian Forest;Riparian Shrub;Lake;Subtidal Marine;Pond/Open Water;Riparian Herbaceous;Sheltered Waters - Marine
	Oporornis agilis	Connecticut Warbler	Blue	S3B	-	-	N	Riparian Forest;Deciduous/Broadleaf Forest;Mixed Forest (deciduous/coniferous mix)
	Setophaga castanea	Bay-breasted Warbler	Red	S2B	-	-	N	Riparian Forest;Conifer Forest - Mesic (average);Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix)
	Setophaga tigrina	Cape May Warbler	Blue	S3S4B	-	-	N	Riparian Forest;Conifer Forest - Mesic (average);Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix)
	Setophaga virens	Black-throated Green Warbler	Blue	S3B	-	-	N	Riparian Forest;Conifer Forest - Mesic (average);Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix)
Mammals	*Bos bison athabascae*	Wood Bison	Red	S2	1-T (Jun 2003)	SC (Nov 2013)	N	Bog;Fen;Swamp;Marsh;Riparian Forest;Riparian Shrub;Lake;Meadow;Grassland;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Pond/Open Water;Riparian Herbaceous;Gravel Bar
	Gulo gulo luscus	Wolverine, *luscus* subspecies	Blue	S3	1-SC (Jun 2018)	SC (May 2014)	N	Bog;Fen;Swamp;Marsh;Riparian Forest;Stream/River;Cliff;Rock/Sparsely Vegetated Rock;Talus;Avalanche Track;Meadow;Grassland;Shrub - Natural;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Krummholtz;Alpine/Subalpine Meadow;Alpine Grassland
	Myotis septentrionalis	Northern Myotis	Blue	S3S4	1-E (Dec 2014)	E (Nov 2013)	N	Riparian Forest;Stream/River;Lake;Caves;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Urban/Suburban;Pond/Open Water
	Pekania pennanti	Fisher	Blue	S3	-	-	N	Bog;Fen;Swamp;Marsh;Riparian Forest;Riparian Shrub;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Krummholtz;Riparian Herbaceous;Gravel Bar
	Rangifer tarandus pop. 14	Caribou (boreal population)	Red	S2?	1-T (Jun 2003)	T (Nov 2014)	**Y**	Bog;Fen;Riparian Forest;Riparian Shrub;Lake;Rock/Sparsely Vegetated Rock;Tundra;Meadow;Grassland;Shrub - Natural;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Pond/Open Water;Riparian Herbaceous;Gravel Bar
	Rangifer tarandus pop. 15	Caribou (northern mountain population)	Blue	S2S3	1-SC (Jan 2005)	SC (May 2014)	N	Bog;Fen;Swamp;Marsh;Riparian Forest;Lake;Rock/Sparsely Vegetated Rock;Tundra;Avalanche Track;Meadow;Grassland;Shrub - Natural;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Krummholtz;Pond/Open Water;Alpine/Subalpine Meadow;Alpine Grassland
	Ursus arctos	Grizzly Bear	Blue	S3?	1-SC (Jun 2018)	SC (May 2002)	N	Estuary;Bog;Fen;Swamp;Marsh;Riparian Forest;Riparian Shrub;Stream/River;Caves;Pasture/Old Field;Talus;Tundra;Avalanche Track;Meadow;Grassland;Sagebrush Steppe;Deciduous/Broadleaf Forest;Conifer Forest - Mesic (average);Conifer Forest - Dry;Conifer Forest - Moist/wet;Mixed Forest (deciduous/coniferous mix);Beach;Urban/Suburban;Riparian Herbaceous;Gravel Bar

potentially be a concern for contamination at the site. Aquatic impacts would be limited to approximately 0.7 ha of wetland habitat at the site, which may reduce food and nutrient supply to downstream fish habitat and amphibian habitat. Terrestrial impacts would be limited to approximately 4.8 ha of forest habitat as a result of clearing and grubbing. A summary of constraints, mitigation, and regulatory requirements is provided in Table 4-2.

4.3.2 Site B

The entirety of Site B is currently zoned for Resource Conservation. Any industrial use contradicts the OCP objectives for this zone; therefore, this site requires 13 ha of rezoning. There are no potential sources of contamination (i.e., industrial operations, waste management, fuel storage or dispensing operations) at Site B or surrounding properties. Aquatic impacts would entail the loss of approximately 105 m^2 of instream habitat,[26] 0.5 ha of riparian habitat, and up to 7.2 ha of wetland habitat due to clearing, grubbing and infilling. Terrestrial impacts would entail approximately 5.2 ha of forest habitat as a result of clearing and grubbing. A summary of constraints, mitigation, and regulatory requirements is provided in Table 4-2.

4.4 SUMMARY AND NEXT STEPS

Based on the findings of our review of background information and our understanding of the proposed works, environmental constraints to the project range from low to medium for Site A and from low to high for Site B. Based on our analysis of the options, Site A is the preferred option from an environmental perspective as there is less overall habitat loss, the constraints in this area involve less regulatory requirements, and we do not anticipate compensation to be required. In addition, Site A is surrounded by industrial use and 2.5 ha Site A is currently zoned for Heavy Industrial use, which aligns with OCP objectives. Site B is a possible option, but the constraints associated with aquatic habitat (i.e., wetlands and tributaries) would require more involved mitigation and potentially compensation.

The key environmental constraints to the Project, which should be addressed during the design and construction planning are:

- Fish and amphibian habitat (i.e., wetlands and tributaries) adjacent to Sites A and B related to footprint impacts (i.e. losses) and water quality (e.g., erosion and sediment control during construction); and
- Wildlife habitat losses, including species at risk, associated with the riparian, wetland, and forested areas.

The pipeline construction will trigger many of the potential issues raised above, and this screening should be refreshed when more design details are known. As previously described, once the detailed designs have been completed for the selected option, an EA report should be completed providing a detailed accounting of habitat impacts based on the detailed design for the Project. The EA report should detail mitigation measures to be implemented and how habitat balance (i.e. losses and gains) is achieved to support the

[26] Based on an assumed 75 m length of channel and 1.4 m width

required applications for environmental permitting and approvals. The EA should involve a site visit to supplement the background information review and confirm or update the site conditions and environmental features. Furthermore, a formal contaminated sites assessment (i.e., a Phase I ESA) would be required for both sites to confirm the potential that soil, groundwater, or vapour at the sites is contaminated relative to applicable standards under current or intended land use.

Table 4-2
Site A and B Environmental Constraints Analysis

Environmental Feature or Value	Site	Constraint Rating	Regulatory Requirements	Summary of Potential Constraints
Fish and fish habitat (i.e., watercourses including wetlands)	Site A	Medium ☆	A Notification (45 days) to the BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNR) for changes in and about a stream (i.e., filling in a portion of the wetland) in accordance with the provincial *Water Sustainability Act;*	No instream impacts are anticipated at Site A; therefore, there are fewer regulatory review requirements.
	Site B	High	A Change Approval (140 days) application to the BC Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNR) for changes in and about a stream (i.e., filling in a portion of the wetland) in accordance with the provincial Water Sustainability Act; A request for project review to Fisheries and Oceans Canada (DFO) for the potential infilling of a stream (i.e., permanent alteration or destruction of fish habitat) in accordance with the federal Fisheries Act (1-2 months) and potential compensation; and Potential fish collection permit from FLNR and DFO (3-6 weeks).	Permanent alteration of fish habitat at Site B requires more regulatory review and scrutiny (i.e. longer approval from FLNR and DFO project review); however, this impact may be avoided through design.
Vegetation and birds	Site A	Low ☆	None; Nest surveys and respecting timing windows	Site A has less overall habitat loss than Site B; however, mitigation for these effects can be simple if breeding timing windows are respected.
	Site B	Low		
Amphibians	Site A	Medium ☆	General Wildlife Permit (including BC Animal Care form) from FLNR for conducting amphibian salvages (45-90 days).	Wetlands are anticipated at both sites, and therefore amphibian salvages prior to construction are likely. Overall habitat loss is higher at Site B.
	Site B	Medium		
Mammals	Site A	Low ☆	None; Species sweeps prior to construction	There is higher likelihood of mammals at Site B; however, mitigation is anticipated to only require species sweeps prior to construction. Overall habitat loss is higher at Site B.
	Site B	Low		
Species at risk	Site A	Medium ☆	None; Species sweeps prior to construction; or General Wildlife Permit (including BC Animal Care form) from FLNR for conducting wildlife salvages (45-90 days).	There is potential for species at risk at either site, and these species are more likely to occur in association with wetland habitat, which is present at both sites. Overall habitat loss is higher at Site B.
	Site B	Medium		

Notes: Potential constraints for Sites A and B are rated as low when best practices apply, medium when constraint can be mitigated but likely involves regulatory requirements, and high when impacts cannot be mitigated and have a high likelihood of requiring compensation.

Review timelines by the applicable agency are from date of submission and are based on experience and are affected by regulatory agency backlog.

Site B is assumed to be located within wetland habitat mapped through VRI; however, aerial imagery does not show indications of wetlands. This would have to be confirmed in the field.

A '☆' indicates the preferred option, either due to ease of mitigation or anticipated magnitude of impact.

5 Potential Existing Customers and Revenue Estimates

5.1 ELECTRICAL

5.1.1 BC Hydro SOP

As stated in Section 2.3, although the BC Hydro Standing Offer Program (SOP) has been suspended and the Fort Nelson region was not eligible, this report will use if as an example of an eligible customer for the potential geothermal electricity produced near the Clarke Lake gas well field.

According to the latest BC Hydro SOP information, the price on electricity offered by the SOP is determined by the region of the point of interconnection. Fort Nelson is in the Northern Rockies Region, which isn't listed in the SOP price list. The closest region listed is the Peace Region, with a listed Base Price (as of 2016) of $102.06/MWh.

The BC Hydro SOP program enrolls projects with a maximum capacity of 15 MW. Assuming 95% uptime for the plant, this equates to 124,830 MWh/year. At the Peace Region listed price of $102.06/MWh, a revenue of $12,740,000/year can be expected. The results are summarized in Table 5-1 below.

Table 5-1
BC Hydro SOP Electrical Revenue Summary

Power Delivered	Annual Hours of Uptime	Total Electrical Energy Delivered	Price of Electricity (2016)	Annual Electricity Revenue
15 MW	8322	124,830 MWh	$102.06/MWh	$12,740,000

5.1.2 Potential Private Customer

Nine km southeast of Sites A and B is the Enbridge Inc. Natural Gas Transmission Plant. While this plant likely has a significant electrical load, it is understood that they potentially self-generate their own power using low cost natural gas. Enbridge Inc.'s cost of generation was not available. In this case it would be for geothermal power to compete with onsite low-cost natural gas power generation. A quantified analysis of this is not within the scope of work. However, the GHG reduction potential of geothermal power may be of interest to them from a marketing and corporate leadership perspective. The client may wish to pursue direct discussion with Enbridge Inc regarding their potential interests in the area. Permitting and regulations regarding electrical transmission potentially between properties would need to be evaluated.

5.2 HEATING

As discussed in Section 2.1.2, after the ORC process, geothermal fluid can still hold significant thermal energy that can be used for nearby thermal loads by running the post-ORC geothermal fluid through a heat exchanger to heat water for use in a district heating network.

Ideally, if multiple customers were subscribed to this heat, a district energy network could be developed to bring the unit cost of connection down. This district energy network would be a network of hot water piping from the geothermal plant to the customer buildings, with cooler return water back to the plant, as discussed in further detail in Section 2.1.2.

To investigate the possibility of selling waste heat to nearby customers, an initial screening was completed to locate potential customers by analyzing the thermal needs of the city of Fort Nelson and its surroundings. There is the potential for a heat load in the nearby town of Muskwa as well, but it was not considered as an individual customer as it is likely the predominantly residential community is too small to significantly impact the overall financial performance discussed here. This could be revisited at a more detailed level of feasibility study.

The thermal loads of major buildings near Fort Nelson have been estimated using the gross floor area of each building and assumed energy intensity factors. The buildings considered in this study represent the ones which have enough thermal load to be of relevance in connecting to a potential district energy network.

The loads have been divided into two categories: Public buildings and hotels, and industrial facilities. The public buildings and hotels are in and around Fort Nelson (North of Sites A and B), while the industrial facility found is south of Sites A and B, so they will be analyzed separately.

5.2.1 Public Buildings and Hotels

The existing public buildings reviewed are:

- Fort Nelson Aquatic Centre
- Fort Nelson Hospital
- Phoenix Theatre
- Public Library
- Fort Nelson College
- Fort Nelson Secondary School and Primary School
- Fort Nelson Recreation Centre

The hotels reviewed are:

- Fort Nelson Hotel
- Blue Bell Inn
- Lakeview Inn and Suites
- Ramada Limited
- Shannon Motel
- Super 8 Motel
- Woodlands Inn & Suites

According to our estimates, the projected load of the public buildings and hotels combined has been estimated at 19,070 MWh/year, or 68,653 GJ/year. As a point of comparison, the *British Columbia Ministry of Environment Community Energy & Emissions Inventory* 2012 numbers for the Northern Rockies Regional District (NRRD) for commercial/small-medium consumers was 302,855 GJ. The NRRD encompasses a large area in northeastern BC, which includes Fort Nelson and several other towns. Fort Nelson is the largest of these towns, so presumably a large proportion of that load resides there, but at this level, it is uncertain what the total potential load would be. The emissions inventory did not provide a data breakdown by community or individual buildings. The analysis below will assume the load of 68,653 GJ/year.

As the business as usual fuel for heating these buildings would likely be natural gas, a competitive price for the district heat energy should consider the current cost of gas energy. The time-of-writing Fortis BC rates for small commercial customers in the Fort Nelson area being broken down as follows:

- Delivery Charge: $4.208/GJ
- Commodity Charge: $1.092/GJ
- Carbon Tax: 1.9864/GJ
- **Total: $7.29/GJ**

To be competitive with natural gas, a $6/GJ price for the district energy heat will be considered. At 68,653 GJ/year, this equates to $412,000/year.

The distance from Site A to the downtown core in Fort Nelson is approximately 7 km, and the distance from Site B is approximately 9 km. Using the best-case scenario of 7 km, the cost for the installation of an insulated supply and return pipe is estimated at $1,900/m for the combined supply and return pipes which is based on observed costs for AE's district energy projects in the lower mainland with a 20% contingency added for the Fort Nelson region. Using this estimate, the pipeline alone would cost about $13,300,000. Each customer would also require an energy transfer station (estimated $50,000 each, $700,000 total), plus there would be large pumps involved in getting the hot water to Fort Nelson and back (estimated cost of $300,000). To bring the total to about $14,300,000. From this high-level approach, the simple payback for this appears to start at about 35 years, which makes connecting a district energy system from the geothermal plant to Fort Nelson financially marginal. Note that this doesn't include the costs of potential building retrofits and capital financing over a longer implementation period. A thorough lifecycle cost analysis and discounted cash flow projection would be needed to examine the effects of commodity fuel price escalation, increasing carbon tax, financing charges, and other factors on financial results. This could be investigated further at a later stage. Additionally, as mentioned above, there is potentially much more heating load in Fort Nelson, which could improve the financial outlook.

5.2.2 Potential Industrial Customers

As mentioned in Section 5.1.2 above, the Enbridge Natural Gas Transmission Plant is located approximately 9 km south of Sites A and B, which creates an estimated pipeline cost of $17,100,000. It is understood that the energy load is largely electrical, potentially self-generated with natural gas, and that for any heating load they have low-cost natural gas, so it appears unlikely that a business case for connecting heat from the geothermal plant would be attractive on financial merits alone. Discussion with Enbridge should focus on determining their actual heating load, and whether the GHG reduction potential of geothermal heating may be a motivating factor in establishing a connection and purchase agreement.

6 Potential New Customers / New Economic Development

A geothermal power plant supplying electricity and heat to the region could attract businesses to the area to capitalize on the opportunity for low-carbon energy. This section will speculate on potential revenue sources for the geothermal electricity and heat.

6.1 ELECTRICITY

Current regulations in BC do not allow for competing with BC Hydro using their transmission or distribution lines, so a private transmission line must be built to supply that energy and needs to be approved by the British Columbia Utilities Commission (BCUC), or the generation of power must be on the customer side of the energy meter. For the building of a transmission line, this would likely be cost prohibitive. To scale up the potential Clarke Lake geothermal plant beyond the 15 MW BC Hydro SOP limit and see a revenue from this higher capacity will require considerable investigation as to the means of supplying electricity to a customer while remaining within regulations. Regardless, the potential for selling electricity to customers other than through the BC Hydro SOP is discussed below.

6.1.1 Industrial Customers

Any major industrial operation in the region could conceivably be an electricity customer for a geothermal plant if the electricity sales are within BC Regulations as mentioned above. This could mean manufacturing, sawmills, processing, or anything of the sort. From a high level, the issue would be that competing with BC Hydro for industrial customers would mean a much lower price per kWh than selling to the BC Hydro SOP. For instance, using the BC Hydro Transmission Rate Schedule 1823A, industrial customers are charged $0.05098/kWh (compared to the BC Hydro SOP purchase price of $0.10206/kWh) along with a demand charge of $8.697/kVA. Depending on the demand charge, this could produce a much lower revenue per kWh than the BC Hydro SOP, so increasing the geothermal plant capacity could produce diminishing returns after the 15 MW BC Hydro SOP limit.

6.1.2 Cryptocurrency Mining

Cryptocurrencies are a form of digital currency based off the RSA algorithm, which is an algorithm that uses cryptography to encrypt and decrypt information and in this case transactions in a secure manner. This allows owners of the currency to have a public (shared) and private (protected) address for their funds and doesn’t require the use of a third party (i.e.: bank) for peer to peer transactions. Cryptocurrencies began in 2009 with the creation of Bitcoin (the first real cryptocurrency), and have been growing in popularity since. As of the time of writing, the cryptocurrency markets contain over 2,000 cryptocurrencies with a total market cap of approximately $USD309 billion.

Generally speaking, cryptocurrencies are created (or ‘mined’) by computing a “hash”, which can be thought of as a solution to a complex algorithm. This is known as ‘proof of work’ and requires considerable computing power and electrical energy. Using Bitcoin as an example, about 90% of the cost of mining is the cost of electricity, which means that miners will seek the lowest cost of electricity possible. Additionally, all the computation involved produces excess heat to be rejected, which is easier to do in colder climates. Therefore, a cryptocurrency mining operation might be attracted to Northern BC.

In 2017, Bitcoin mining used an estimated total of 30 TWh (30,000,000,000 kWh) of electrical energy. The number of total miners is unknown, but it can be estimated at about 300,000. This means that each miner uses about 100,000 kWh of electrical energy per year, which at a cost of $CAD0.06/kWh (comparable to BC Hydro transmission rates), would cost about $CAD6,000, if that price could be guaranteed. Some miners provide a lot of computing power (server rooms and warehouses), and some provide relatively little (e.g.: a laptop), but that can be used as an average estimate.

With these numbers, if 100 average Bitcoin miners could be attracted to the Fort Nelson area as electricity customers for the geothermal plant, then an additional annual revenue of $CAD600,000 is possible. These numbers are speculative, but the potential is there for this type of customer.

It should be noted that due to the speculative nature of this industry, cryptocurrency miners present an uncertainty as to whether they can be considered a long-term customer.

6.2 HEAT

6.2.1 Greenhouses

Greenhouses to grow fruits and vegetables can be heated in the winter months to produce valuable food all year round. This presents an opportunity to use the excess heat from a geothermal plant as a reliable and low carbon method for greenhouse heating, which would not only improve the economics of the geothermal plant, but would provide another economic opportunity to the area through expanded agriculture.

According to the Government of Canada's Climate Normals data, Manitoba has a comparable climate to Fort Nelson in terms of heating degree days (Thompson, Lynn Lake, and Winnipeg were compared to Fort Nelson and their summed heating degree days between Sept-May were found to be within 15%). According to the Government of Manitoba, a greenhouse uses 2,100 MJ/m^2 during the heating season of September through to May. This means that a 1,000 m^2 greenhouse would use 2,100 GJ of heat per year. Including an assumption of an efficiency of 80%, this inflates to about 2,600 GJ per year of actual delivered heat.

If this estimate from Manitoba were applied to the Fort Nelson region, using the same conservative price of $6/GJ, this works out to about $CAD15,600/year for a 1,000 m^2 greenhouse. With enough greenhouses brought to the area, this could be a significant source of revenue.

6.2.2 Other Potential Uses for Heat

There are numerous other industrial uses for geothermal waste heat. Figure 6-1 shows some options for geothermal energy in addition to electricity production.

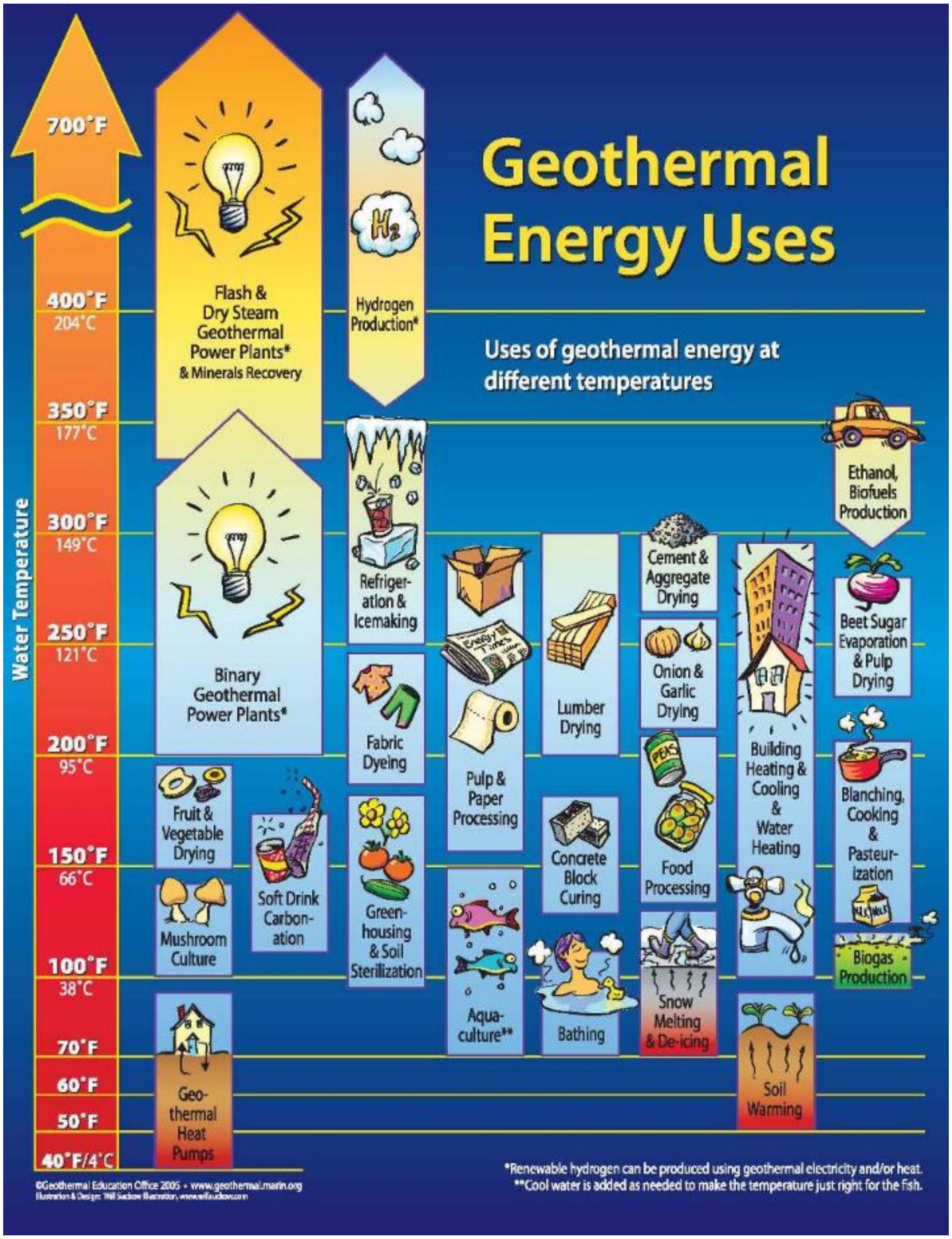

Figure 6-1
Uses of Geothermal Energy/Heat
Source: Geothermal Education Office
https://www.geothermal.org/PDFs/Articles/colorfulposter.pdf

7 Power Plant Development Cost Estimate

The construction costs for a geothermal plant can be broken down into the following categories:

1. Geothermal Well Drilling
2. Plant Site Development
3. Well Site Development
4. Well Pumps (Line Shaft Pumps)
5. Lateral Piping to Geothermal Plant
6. Organic Rankine Cycle Equipment
7. Plant Building Construction
8. Electrical Grid Interconnection Costs
9. Geothermal Permit and Well Authorizations
10. Engineering Fees
11. Environmental Fees

A Class D (± 50%) cost estimate is broken down in detail in the sections below.

7.1 GEOTHERMAL WELL DRILLING

AE contacted several drilling contractors and consultants and received two estimates for well drilling costs. Some relevant information was unknown (production water chemistry, exact subsurface conditions, requirements for wellsite construction), so these are high-level estimates, but will suffice for the purposes of this report. The information provided to the drillers for the cost estimate was the following:

- Depth of well is approximately 2,000 m (based on an approximation of Table 12 in Palmer-Wilson et al., depth of reservoir top of 1935 m for Clarke Lake).
- Subsurface conditions consist of varied sedimentary rocks including dolomite, limestone, mudstone, etc. (from Renaud et al., 2018).
- Water chemistry is unknown.

The two estimates received were from Ground Source Energy and Magus Engineering, and were the following:

Ground Source Energy:

Assumptions: Similar wells drilled in potash to 1800 m averaged $CAD 1.5 million per well, so an estimate of $1.8 million would be sufficient for high level feasibility.

Magus Engineering:

Assumptions: 9-5/8" surface casing, 7" production casing, 20 or 13-3/8" conductor pipe.

Price: Approximately $1.7 million per well.

Since these two estimates are close, the assumption of $1.8 million per well will be used to remain conservative.

The exact number of wells that will be required for the 15 MW plant is unknown at this point as the achievable brine flow rate per well is unknown. As briefly mentioned in Section 1.3, Palmer-Wilson et al. reviews several studies that either infer or assume achievable flow rates from wells in the area based on previous studies. From this review, the authors present upper and lower bounds for the brine flow rates as two separate cases of 100 kg/s and 30 kg/s, which will be used in this report as well. For the case of 100 kg/s of achievable brine flow rate (Scenario 1), 10 production wells and 5 injection wells would be required, for a total of 15 wells. If the achievable brine flow rate was reduced to 30 kg/s (Scenario 2), then 31 production wells and 16 injections wells would be required, for a total of 47 wells.

These two scenarios represent well drilling cost estimates of $27 million and $85 million, which is a large range, and comparing to other costs below, is a major driving factor of the total cost of the plant. Due to this large range, these scenarios will be considered separate going further. The input data and costs are summarized in Table 7-1.

It should be noted that each well site will likely need a certain amount of site development for drilling equipment and maintenance access. This will be analyzed separately in Section 7.3.

Table 7-1
Well Drilling Cost Estimate Summary

Scenario	Achievable Flow Rate [kg/s]	Production Wells	Injection Wells	Total Wells Required	Cost Per Well [$CAD]	Total Cost Estimate [$CAD]
1	100	10	5	15	$1,800,000	**$27,000,000**
2	30	31	16	47	$1,800,000	**$85,000,000**

7.2 PLANT SITE DEVELOPMENT

The Class D cost estimates for the required civil construction tasks are summarized in. The basis for these cost estimates was developed in Section 3.2.

Table 7-2
Civil Construction Tasks Required Cost Estimate Summary

Description of Work	Site A	Site B
Clearing	$33,000	$65,000
Grubbing	$46,000	$91,000
Stripping	$117,000	$234,000
Imported Fill Material	$1,300,000	$2,600,000
Granular Material	$1,950,000	$1,950,000
Drainage	$118,000	$118,000
Fencing	$376,000	$376,000
Subtotal	**$3,940,000**	**$5,434,000**
Mobilization / De-mobilization	$197,000	$271,700
Contingency (50%)	$1,970,000	$2,717,000
Total	**$6,107,000**	**$8,422,700**

As detailed in Section 3.2, the cost to develop the 13-hectare plant will depend on the site chosen. Site A is estimated at $6.1 million, and for Site B is estimated at $8.4 million. Since this cost discrepancy is relatively low ($2.3 million) as compared to the well drilling costs, a mid-range value of $7.3 million will be used as an estimate for Scenarios 1 and 2 (15 wells vs 47 wells).

7.3 WELL SITE DEVELOPMENT

As detailed in Section 3.2 and 7.2, the cost of site development for the 13-hectare plant is estimated at a mid-range value of $7.3 million. This equates to approximately $560,000 per hectare.

From observing geothermal plants on Google Earth, it’s been observed that a well site requires approximately 0.1 hectares of space (approximately 30 m x 30 m).

Table 7-3 shows the estimated cost of well site development for Scenarios 1 and 2.

Table 7-3
Well Site Development Cost Estimate Summary

Scenario	Total Wells Required	Hectares Per Well	Total Hectares	Cost Per Hectare [$CAD]	Total Cost Estimate [$CAD]
1	15	0.1	1.5	$560,000	**$840,000**
2	47	0.1	4.7	**$560,000**	**$2,600,000**

7.4 WELL PUMPS (LINE SHAFT PUMPS)

The production wells will likely require pumps to bring the geothermal fluid to the surface to exchange heat with the working fluid, and potentially a pump for re-injecting the geothermal fluid back in the reservoir. For the most part, these pumps are known as line shaft pumps. A schematic representation of a line shaft pump installation is shown in Figure 7-1.

Since the pressure and chemistry of the reservoir is unknown at this point, it is difficult to get an accurate cost estimate on the pumps. Additionally, the injection wells may not need pumps if the pressure of the reservoir is low enough, or the pumps may be much smaller or a different model than the production pumps. For the purposes of this report, it will be assumed that each production well requires one line shaft pump, and 50% of the injection wells will need a similarly priced injection pump. This cost is expected to cover any well completions as well.

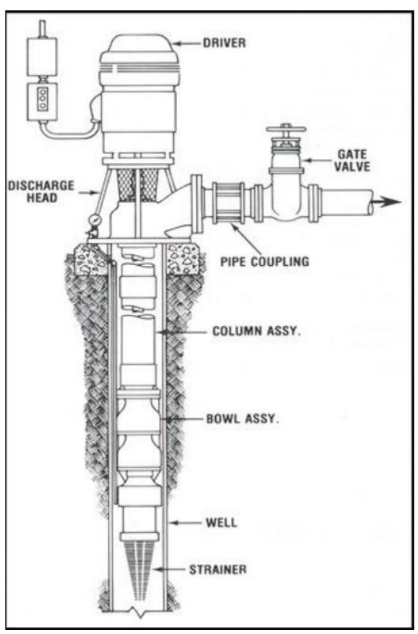

Figure 7-1
Line shaft pump installation schematic, from *Engineering Aspects of Geothermal Production Well with Down Hole Pumps (Kaya and Mertoglu, 2005)*

A local pump provider was contacted for a cost estimate for a line shaft pump for a geothermal application with fluid temperatures of 110 °C at 2000 m depth. The provider understood that the flow rates were unknown between a range of 30 L/s and 100 L/s, and that the casing size of the well is also unknown at this point.

With that information at hand, the pump provider estimated a budget cost of $1 million per pump, while also considering that a fluid temperature of 110 °C and a 2000 m depth well are both engineering issues to be overcome through materials selection and investigation into the pump hydraulic head requirements.

Using that number, the cost estimates for Scenarios 1 and 2 are presented in Table 7-4.

Table 7-4
Well Line Shaft Pump Cost Estimate Summary

Scenario	Production Wells	Injection Wells	Pumps Required	Cost Per Pump [$CAD]	Total Cost Estimate [$CAD]
1	10	5	13	$1,000,000	**$13,000,000**
2	31	16	39	$1,000,000	**$39,000,000**

The BC Oil & Gas Commission provides some well data in a public database, which could be accessed in a future, more detailed study to further investigate the requirement of and costs of these pumps.

7.5 LATERAL PIPING TO GEOTHERMAL PLANT

The lateral piping connects the wells to the ORC plant. Materials for and construction of this piping carries a significant cost. Spacing the wells further apart increases the cost of lateral piping but is required to avoid underground well interference. Through a communication with Dr. Jonathan Banks at the University of Alberta on January 22, 2019, a conservative estimate of 500 m spacing between wells will be assumed based on general European geothermal industry standards.

Using a simple model, estimates for well distances were calculated. Scenario 1 and Scenario 2 would require 11.3 km and 62.3 km of lateral piping, respectively.

To estimate the cost of this lateral piping, the following is assumed:

- 150 mm diameter, A106 steel pipe, CL 150.
- 75 mm thick insulation on steel pipe with cladding.
- Ground level pipe support rack with steel pipe piles.
- Clear access with crane and/or picker truck along piping right-of-way.
- Welded construction.

The results of a 2009 study conducted by AE were adapted to estimate these costs. After accounting for 2.5% annual inflation, and a $USD to $CAD conversion of 1.33, a cost of $365,000/km was determined. In addition, for construction access to the pipelines, a road will need to be constructed alongside of it. According to the BC Ministry of Transport Construction and Rehabilitation Guide, producing a two-lane low volume road in ‘Moderate Conditions’ comes at a cost of $542,000-$867,000/km. Since this would be a northern, wooded area, assuming a value on the upper end of this range, or $867,000/km, is prudent. There are some existing logging and natural gas access roads near both Sites A and B, and designers will likely find ways to combine pipelines next to a single road, so it will also be assumed that only 50% of the pipeline length requires a new access road built next to it, so the cost per overall km can be reduced to $435,000. The road costs might decrease if contractors local to Fort Nelson are involved.

In total, considering that only 50% of the pipeline length requires a road built, the effective cost per km of lateral piping (including access roads) would be $800,000/km ($365,000/km for the lateral piping, and $435,000/km for access roads). The total costs for Scenarios 1 and 2 are in Table 7-5.

Table 7-5
Lateral Piping Cost Estimate Summary

Scenario	Piping Distance [km]	Cost Per km [$CAD]	Total Cost Estimate [$CAD]
1	11.3	$800,000	$9,000,000
2	62.3	$800,000	$50,000,000

The materials proposed for lateral piping should be re-checked once the water chemistry is known.

7.6 ORGANIC RANKINE CYCLE EQUIPMENT

Vendors were approached for pricing information on their ORC equipment. The following was provided as input for the pricing:

- Geothermal Fluid Temperature: 110 °C
- Hot Water Flow Rate: 100 L/s
- Annual Hours of Operation: 8322 hours

Of the larger scale ORC equipment vendors noted in Section 2.1, estimates were received from Ormat Technologies Inc. and Turboden. Due to the differences in business model and quoting documentation, the estimates received are not directly comparable. The information received will be discussed below, with a Class D cost estimate for the ORC equipment proposed.

Ormat Technologies Inc.

Ormat was hesitant to provide any costing information. With further explanation of the goal of this report, Ormat did not provide a detailed breakdown but suggested a range of total costs.

According to Ormat Technologies Inc., a standard Ormat plant in the United States, without considering the wellfield, permitting, interconnection agreements, or remote location can cost in between US$2,500 to US$3,500 per kW installed. At the current exchange rate of US$1: CAD$1.33, this can be converted to a range of CAD$3,325 to CAD$4,650 per kW installed.

The ORC equipment provided in this estimate includes the supply and installation of:

- Turbine/generator skid including the oil system.
- Vaporizers.
- Preheaters.
- Air- or water-cooled condensers (along with a potential cooling tower for water cooled condensers).
- Other balance of plant (BOP) items provided include an air compressor system, chemical system controls, electrical transformers, switches, and MCCs.

Since the concept model for this plant is a 15 MW (15,000 kW) output, using Ormat's estimate, the cost of the installed ORC equipment can be estimated in range of CAD$50,000,000 to CAD$70,000,000, or an approximate mid-range value of CAD$60,000,000.

Turboden

AE received a sales proposal including an equipment list and lump sum cost estimate from Turboden. This quote included the supply, but not the transportation or installation, of the main ORC equipment, including the following:

- Fluid heat exchangers
- Turbine/generator skid
- Air cooled condenser
- Feed pumps and all required valves
- Instrumentation and controls

The quote does not include the BOP items that were included in Ormat's estimate, nor does the quote include transportation or installation.

The quote provided an indicative price of EUR€14,850,000, which using the current exchange rate of EUR€ : CAD$1.50, comes to CAD$22,275,000. It should be noted that Turboden proposed a 15 MW plant that delivers a net 13 MW (2 MW lost to running plant equipment). Since the revenue estimates are based on selling 15 MW to the grid, this estimate should be increased by a factor of 17/15 to bring it to a 17 MW plant that delivers 15 MW. This also assumes that the costs scale linearly with plant capacity, and that 2 MW is enough to run the 17 MW ORC equipment. With this increase, the Turboden estimate is $25,245,000.

Through feedback from Turboden, the transportation and installation costs can be estimated at $CAD10 million. If the balance of plant items are estimated at another $CAD10 million, then a reasonable total estimate for Turboden would be CAD$45,000,000. The balance of plant items cost estimate represents the highest uncertainty in this estimate.

Class D Estimate

There are many unknowns in the Ormat and Turboden estimates. For the purposes of creating a Class D cost estimate, it is sensible to take a value in between the lower Turboden and higher Ormat price and assume that the Class D ±50% captures the probable range of cost for the supply, delivery, and installation of the ORC equipment. With all this information in place, a proposed cost estimate for this portion of the plant is CAD$50,000,000 (range of costs of $25,000,000 - $75,000,000, which covers both estimates). The information presented in this section is summarized in Table 7-6.

Table 7-6
ORC Equipment Cost Estimate Summary

Uses of Geothermal Energy/Heat	Uses of Geothermal Energy/Heat
Ormat Technologies Inc.	$60,000,000
Turboden	$45,000,000
Proposed Class D Cost Estimate*	**$50,000,000**

*Including balance of plant items, transport, and installation.

7.7 PLANT BUILDING CONSTRUCTION

From discussions with Turboden, the ORC equipment and all electrical cabinets, panels, and motor control centres will need to be housed in a building. From observing Ormat's Brawley Geothermal Plant in Imperial County, California (a 13 MW plant), it is estimated that a high ceiling, single story, 600 m^2 building will be required for either Scenarios 1 or 2. The following estimated gross building costs are based on reference guide cost data for the Canadian construction industry and past similar scope projects. This estimate reflects a class D costing assuming the following conditions:

- Reinforced concrete substructure
- Combination concrete and steel superstructure
- Basic industrial requirements for partitions, doors and finishing
- Light industrial building mechanical and electrical

The cost estimate for the plant building including a breakdown for the building elements is shown in Table 7-7.

Table 7-7
Plant Building Cost Estimate

Building Element	Cost per unit area [$CAD/m^2]	Total Area [m^2]	Cost [$CAD]
Substructure	394	600	$236,400
Structure	811		$486,600
Exterior, interior, partitions & finishes	376		$225,600
Building mechanical & electrical	987		$592,200
Total:	2,568		$1,500,000

7.8 ELECTRICAL GRID INTERCONNECTION COSTS

All cost associated with the ORC electrical equipment is included in Section 7.6, and Section 7.7 covers the plant building electrical (lighting, HVAC, etc.). The electrical equipment to connect the generator to the BC Hydro grid is a separate cost, along with the associated electrical engineering services and the installation and commissioning of the equipment. Through investigation of these costs, it has been determined that there are four main components to the electrical grid interconnection costs to consider. These are:

1. Powerhouse Interconnection Electrical Equipment
2. 144 kV Transmission Voltage Substation
3. Transmission Line Construction
4. BC Hydro Interconnection Fees

Each cost will be estimated separately, followed by a summary.

7.8.1 Powerhouse Interconnection Electrical Equipment

This equipment is the electrical equipment and switchgear required to control the power being generated by the turbine-generator coupling. From internal experience with connecting 15 MW power plants to the grid, we estimate the cost of the powerhouse electrical grid interconnection equipment including engineering services, main control panel including a human-machine interface, installation and commissioning at $2.7 million.

7.8.2 144 kV Transmission Voltage Substation

Electricity is usually generated between 13-25 kV, but the nearby BC Hydro transmission line is 144 kV, so an additional substation will be required to be able to tie in at the required voltage. It is possible that there is a suitable existing BC Hydro substation nearby that can be used, but it is unknown at this time, so it will be assumed as a worst case scenario that a new one will need to be built.

From internal experience with connecting electricity generating plants to high voltage lines in Northern BC, we estimate this cost at $5 million.

7.8.3 Transmission Line Construction

The 144 kV substation could be on site at the geothermal power plant with a 144 kV transmission line run to the tie in location, or a lower voltage line could be run with a substation stepping up to 144 kV closer to the tie in.

Previous researchers used a BC Hydro reported cost of $84,800/km for a 25 kV transmission line to connect to BC Hydro along with an assumption of 10 km required. Figure 1-2 above shows a BC Hydro 144 kV transmission line going right by Sites A and B at an estimated distance of 2 km. Thus, if it is assumed that a 25-kV line will be used and a substation will be placed closer to the tie in location, then a reasonable cost estimate for this transmission line is $200,000.

7.8.4 BC Hydro Interconnection Fees

BC Hydro charges interconnection fees to tie into its grid. These fees cover the cost of any needed studies performed (see Section 2.3) and corporate overhead costs. These costs can be significant. From internal experience with connecting electricity generating plants to high voltage lines in Northern BC, we estimate this cost at $5.6 million.

7.8.5 Electrical Grid Interconnection Costs Summary

Table 7-8 shows the summary of electrical grid interconnection costs with a total of $13.5 million.

Table 7-8
Electrical Grid Interconnection Costs Summary

Powerhouse Interconnection Equipment [$CAD]	144 kV Substation [$CAD]	Transmission Line [$CAD]	BC Hydro Interconnection Fees [$CAD]	Total [$CAD]
$2,700,000	$5,000,000	$200,000	$5,600,000	$13,500,000

7.9 GEOTHERMAL PERMIT & WELL AUTHORIZATIONS

The process drilling geothermal wells in BC requires engagement with the provincial government and the procurement of certain permits. This section aims to outline that process, as well as estimate the costs involved where it is clear.

The Project Proponent can apply for a geothermal exploration license, which is a one-year license that is renewable up to seven times and enables the owner to purchase well allowances to drill wells at a cost of $12,000 per well. A land use permit is also required for this. There is also a 20-year lease option as opposed to the one-year permit, but it is not clear at this point how to obtain this, nor is it clear what the associated costs would be.

The process to obtain a geothermal exploration license and well allowances is outlined as follows:

- Step 1: Identify desired land parcel and apply for a geothermal exploration permit with the Government of BC.
- Step 2: After a pre-tenure review by the government, there is a public sealed bidding process for the exploration permit.
- Step 3: If the exploration permit is successfully obtained, then a land use permit can be applied for and received.
- Step 4: Once both the land use permit and the geothermal exploration permit are held, then well allowances can be purchased.

Currently, the only predictable costs are the land-use permits and the well allowances. The geothermal exploration permit is based on a sealed bidding process, so it is hard to predict. Based on the last two public record of geothermal exploration bids, a cost estimate of $100,000 is used here. For the well allowances, since the total amount of wells is different under Scenario 1 and Scenario 2, these will be analyzed separately.

The overall cost estimate for the geothermal permit and well authorizations is summarized in Table 7-9. Note that this does not include the cost of a potential 20-year lease as it is unknown at this time what the cost would be.

Table 7-9
Geothermal Permitting and Well Allowance Cost Estimate Summary

Scenario	Geothermal Exploration Permit [$CAD]	Land Use Permit [$CAD]	Well Allowances [$CAD]	Total [$CAD]
1	$100,000	$3,465	$180,000	$283,000
2	$100,000	$3,465	$564,000	$667,000

7.10 ENGINEERING FEES

This section assumes that the project owner will retain an engineering consultant to manage the design and construction of the geothermal plant. From internal experience and industry norms, it is estimated that 15% of the capital cost will be the cost of the engineering fees throughout the project.

Except for the Electrical Grid Interconnection Costs (Section7.8), which included the engineering fees, no other capital expenses have had engineering fees associated with them yet. The fee in this section aims to estimate the cost of the engineering expenses relating to all other capital expenses by assuming 15% of the considered capital expense as the cost of the engineering fees.

For each of Scenarios 1 and 2, the sum of the capital expenses that will result in engineering fees and the associated 15% cost for the engineering fees are shown in Table 7-10.

Table 7-10
Engineering Fees Summary

Scenario	Capital Expense Considered [$CAD]	Engineering Fees [$CAD]
1	$109,000,000	$16,300,000
2	$235,000,000	$35,300,000

7.11 ENVIRONMENTAL FEES

Prior to construction, environmental assessment and permits would be mandatory. During construction, compensation, salvages and sweeps, and revegetation could also be required, but it isn't clear at this point. Additionally, the cost of construction monitoring from an environmental professional is considered. These costs are relatively minor as compared to other construction costs and would be different for Site A and Site B and are shown in Table 7-11.

It is difficult to quantify environmental fees with the conceptual design at a Class D (± 50%) level. More investigation and design would be required to increase the accuracy of this estimate.

Table 7-11
Environmental Fees Examples

Expense	Site A Cost [$CAD]	Site B Cost [$CAD]	Comments
Contaminated Sites Assessment	$8,000	$8,000	
Environmental Assessment	$20,000	$20,000	
Permitting and Regulatory Liaison	$3,000	$5,000	
Compensation Design	N/A	$15,000	Site A requires no compensation. Site B has the potential for instream work.
Salvages and Sweeps	$30,000	$40,000	From experience with other areas.
Revegetation/Planting	$20,000	$120,000	Site A – small amount around the building. Site B – compensation for a portion of the creek.
Construction Monitoring	$200,000	$200,000	Assumes 1 site visit per week for a four year construction timeline.
Total:	**$281,000**	**$408,000**	

Since these costs are relatively minor, an estimate of $400,000 will be used for both Scenarios 1 and 2.

Revegetation from the lateral piping is not included in this cost as it is unknown whether it is required.

7.12 TOTAL COST ESTIMATE

A summary of the itemized Class D cost estimates for both Scenarios 1 and 2 are shown in Table 7-12.

Table 7-12
Total Cost Estimate Summary

Item	Cost [$CAD]	
	Scenario 1	Scenario 2
Geothermal Well Drilling and Development	$27,000,000	$85,000,000
Plant Site Development	$7,300,000	$7,300,000
Well Site Development	$840,000	$2,600,000
Well Pumps	$13,000,000	$39,000,000
Lateral Piping to Geothermal Plant	$9,000,000	$50,000,000
Organic Rankine Cycle Equipment	$50,000,000	$50,000,000
Plant Building Construction	$1,500,000	$1,500,000
Electrical Grid Interconnection Costs	$13,500,000	$13,500,000
Geothermal Permitting and Well Authorizations	$280,000	$670,000
Engineering Fees	$16,300,000	$35,300,000
Environmental Fees	$400,000	$400,000
TOTAL:	**$139,000,000**	**$285,000,000**

Thus, the cost of developing a 15 MW geothermal power plant near Clarke Lake is estimated in the $139-$285 million range, depending on the number of wells required (Scenario 1 vs Scenario 2).

7.13 COMPARISON TO PREVIOUS RESULTS

Palmer-Wilson et al., 2018 showed estimated capital costs of $216.1 million and $518.6 million for Scenarios 1 and 2, respectively. These are both significantly higher than the costs estimated in this report.

The three main reasons for this are as follows:

1. The previous results scaled the cost of the ORC equipment from a 2.5 MW plant to a 15 MW plant. Since these costs do not scale linearly, this may have resulted in an overestimate.
2. The previous results estimated the well drilling costs at $4.7 million, while this study estimates them at $1.8 million, or a difference of $2.9 million per well.
3. The capital cost values presented in the Techno-Economic assessment may not reconcile based on the presented equation and inputs.

It should be noted that with the high number of unknown facts of significance, that further investigation is necessary to determine accurate costs for these values.

7.14 SIMPLE ECONOMIC ANALYSIS

Section 5.1 estimated the annual electrical revenue at $12,740,000. According to Turboden, operational and maintenance costs can be expected to be €5/MWh/year, or CAD$7.50/MWh/year at the current exchange rate. Since the plant will produce an estimated 124,830 MWh per year, this works out to an approximate $936,000/year, resulting in an earnings before interest, tax, depreciation, and amortization of $11,800,000 per year.

Based on the cost estimates for Scenarios 1 and 2 presented in Table 7-12, this results in an estimated simple payback range of 12-24 years, ignoring the cost of financing and taxes. Note that this carries the Class D ±50% level of certainty.

The Techno-Economic Assessment presented a more rigourous and statistical-analysis focused financial evaluation. It is recommended that this work be refreshed given the findings of this study.

8 Recommended Next Steps

Should Geoscience BC wish to pursue the Project further, the following recommendations should be considered to gain a higher level of confidence in the feasibility of implementing a geothermal power plant in the Clarke Lake Reservoir area.

8.1.1 Recommendation #1

AE identified several discrepancies between our capital cost estimate and the estimate provided in the previous techno-economic report. We were unable to reconcile these discrepancies and some inconsistencies in the resulting financial analysis (refer to Section 1.3). It is recommended that the previous study financial analysis be reviewed.

8.1.2 Recommendation #2

Based on the cost estimates for Scenarios 1 and 2 presented in Table 7-12, the project simple payback is estimated to be in the range of 12-24 years at a Class D (±50%) level of certainty.

From this result, it is recommended that Geoscience BC determine the go / no-go decision to continue evaluating this opportunity. If the decision is made to continue evaluating the project, the next recommendations should be considered.

8.1.3 Recommendation #3

Engage with BC Hydro and start preliminary discussions around the opportunity to either apply their Standing Offer Program (currently on hold as noted in Section 2.3) or to develop an independent electricity purchase agreement. It is important to note that Fort Nelson was not part of the previous SOP and this needs to be addressed with BC Hydro.

The electricity revenue from the sale to BC Hydro represents the large majority of the project revenues. Therefore, confirmation of a vehicle to engage with BC Hydro to form an electricity purchase agreement, the electricity purchase rate, and the timing of this agreement are priority items to confirm the financial viability of the project.

8.1.4 Recommendation #4

Develop a contact at Enbridge Inc. and begin the process of exploring their interest in becoming a customer for low-carbon electricity and/or heat.

Enbridge Inc. is identified as a potential anchor load for the proposed geothermal power plant. Confirming their interest and their associated potential load profile will provide additional financial security to the project. Note that the success of developing Enbridge Inc. (or any large customer) will likely depend on an internal champion for carbon reduction within the organization. If possible, identify and engage with any local energy managers or GHG reduction strategists.

8.1.5 Recommendation #5

Begin further consultation with First Nations, the Province of BC, and any local stakeholders in the Fort Nelson region.

8.1.6 Recommendation #6

Continue refining the geothermal project boundaries, definition, scope and budget by undertaking a detailed feasibility study. The goal of this study would be to:

- Better define the geothermal heat resource; refer to recommendation #7.
- Better define the district heating demand through a building inventory, energy load analysis and future growth projections.
- Review the proposed plant locations.
- Review and update the plant capacity/sizing estimates.
- Prepare a conceptual plant process flow diagram(s), plant layout, single line diagram.
- Size all major equipment for the project – obtain supplier quotes for major equipment.
- Update the capital and operating and maintenance cost estimates based on the developed drawings. At this stage, a class C estimate is the recommended target.
- Prepare a financial analysis for the project.
- Undertake a desktop environmental study.
- Identify required project regulatory requirements and permitting.
- Identify ownership and financing models.
- Identify next steps in the development of the project.

8.1.7 Recommendation #7

Further the understanding of the geothermal reservoir through in-situ testing to determine achievable flow rates, capacity, water chemistry, pumping dynamic head, temperatures, and all other relevant parameters. Note that performing this testing will have considerable costs.

8.1.8 Recommendation #8

Consider the development of a demonstration/pilot scale power generation project using one of the vendors that provide smaller ORC technology packages. This unit could potentially be powered on any test wells completed as part of the in-situ reservoir study.

Certification Page

This report presents our findings regarding the Geoscience BC, Clarke Lake Geothermal Pre-Feasibility Study.

Respectfully submitted,

Prepared by:

R. J. ARELLANO
29070
BRITISH COLUMBIA
2019-08-29

Graham Ballachey, CEM, P.Eng.
Mechanical Engineer

Ruben Arellano, P.Eng.
Project Manager

Reviewed by:

Aaron McCartie, P.Eng.
Mechanical Engineer
GB/RA/AM/lp