Mapping Techno-Economic Feasibility of Geothermal Resources in Alberta, Canada

Gordon Brasnett[1], Catherine Hickson[2], and Roman J. Shor[3]

[1]Sproule Associates Ltd., Calgary, Alberta

[2]Alberta No. 1, Edmonton, Alberta

[3]University of Calgary, Calgary, Alberta

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ABSTRACT

Identifying favorable locations to place geothermal projects typically starts with evaluating the geothermal gradient in a region; however, the feasibility of a project also depends on ease and costs of drilling, proximity to customers to offtake excess heat energy and other practical factors. This research meshes a variable-price model with multiple geospatial data sets using a geographic information systems (GIS) platform to produce a map set illustrating the estimated status of engineered geothermal systems (EGS) - both for electrical generation and direct-use applications in the province of Alberta, Canada.

By combining several map layers, a region's suitability for geothermal projects is categorized by evaluating multiple technical and economic criteria. Costs and potential revenues associated with development are estimated to provide an overview of geothermal energy's economic viability across the province with a net present value (NPV) calculation. The resulting interactive maps model a picture of the estimated feasibility of geothermal energy in Alberta under varying techno-economic scenarios. Economically favorable locations for geothermal project development generally occurred in the Western portion of the province where Precambrian basement rock is deepest, along existing infrastructure corridors, and near population centers or industrial facilities to off-take heat energy.

1. Introduction

Alberta is a province in western Canada with a cold and dry continental climate. In Alberta, the Western Canadian Sedimentary Basin (WCSB) overlies Precambrian basement rock and is deepest (approximately 3.7 miles or 6 km thick) near the Rocky Mountains in the south-western portion of the province and shallows to the north and north-east where Precambrian basement is present at surface in the north-eastern corner of the province. The WCSB is home to prolific oil and gas reserves that have been a driver of Alberta's economy for decades.

Figure 1: Location of Alberta, Canada.

The goal of this work was to identify areas in the province of Alberta that are best suited for the economic development of Enhanced/Engineered Geothermal System (EGS) projects. To this end, a provincial-scale model was created using multiple geospatial data layers and an interactive model was developed on a 5 km x 5 km grid (3.1 mile x 3.1 mile). Geospatial data layers were built using ArcGIS Pro GIS software developed by Esri and exported into data analytics software developed by Tableau. The interactive model was published online via the Tableau Public interface which provides the functionality for online users to explore modifications of key techno-economic conditions required for the viability of geothermal projects either for direct-use heating applications (40°C/104°F, 80°C/176°F resource temperatures) or for combined heat and power applications (120°C/248°F, 150°C/302°F resource temperatures). The interactive model also incorporates potential value-add aspects of geothermal projects such as income derived from carbon credits from CO_2 sequestration or revenues from mineral extraction if geochemistry data in the area indicates viable concentrations of lithium in subsurface fluids at the depth of the geothermal resource temperature.

This paper contributes to broadening the understanding of geothermal energy's viability near Alberta's communities and the province's existing infrastructure network through a provincial-scale, open-source map set and multi-dimensional model that can serve as a guide for detailed follow up studies or for more comprehensive mapping projects. The models developed in this research project can serve as a screening tool in Alberta to evaluate the feasibility of various geothermal energy project types (40°C, 80°C, 120°C, or 150°C) while exploring the value of cost reductions of various project components such as drilling cost reductions. Publishing open-source results in an interactive web-based format also serves to improve awareness of the viability of different forms of geothermal energy in Alberta. The tool provides a platform for drillers, construction managers, reservoir engineers, and developers to communicate across disciplines and understand which key cost, revenue, and output metrics need to be met for a geothermal project's economic viability.

1.1 Literature Review

Early research evaluating the geothermal gradient – the rate at which temperature increases with subsurface depth – in Alberta began in the mid-1980s by Lam & Jones (1984) with work continuing in the early 1990s by Bachu & Burwash (1994, 1991). Since then, geothermal maps of the WCSB have continued to evolve through integration of bottom hole temperature data from additional wells, debiasing temperature data to better reflect subsurface conditions, including geologic structure mapping, and improving the resolution of subsurface models (Ferguson & Ufondu, 2017; Grasby et al., 2012; Gray et al., 2012; Hofmann et al., 2014; Palmer-Wilson et al., 2018; Weides & Majorowicz, 2014).

The geothermal gradient maps developed by Majorowicz (2018) are a key data set which represents the most up-to-date, province-wide, geothermal gradient data for Alberta. This data set represents a foundation whereby existing geological and subsurface temperature models may be incorporated with other data supporting economic estimates in the interest of developing a techno-economic model in a similar fashion as described by Banks & Harris (2018) and Palmer-Wilson et al. (2017, 2018). The multi-criteria, weighted parameter evaluation method can be applied to mapping applications by assigning values for each geologic or economic criteria layer to every grid cell on a map. This is a workflow described by Harms et al. for identifying geothermal prospects in East Africa and Northeast British Columbia where surface features are identified and plotted, attributes are correlated with subsurface temperature data, and the model is compared with known results (Harms et al., 2020; Harms & Kalmanovitch, 2021).

2. Methodology

We follow a similar approach described by Harms & Kalmanovitch (2021): spatial data sets (geothermal gradient, depth to Precambrian basement rock, geochemistry concentrations, geologic structure maps, distance to nearest transmission line, distance to nearest road, etc.) are interpolated onto an evenly spaced grid. For this model, each grid cell represented the centre of a 5 km x 5 km area and had key information assigned to it; where data was unavailable, reasonable assumptions were be made to assign plausible approximate values, or the model was cut-off. Following the approach described by Palmer-Wilson et al. (2017), variable weighting parameters were applied to many of the spatial data sets so that project costs and revenues can manipulated via interactive sliders so that the model's user can gain an understanding of what numbers to target for a geothermal project in a particular region to be viable. A summary of the layers estimating costs and potential sources of revenue as well as the variable parameters for each layer are displayed below in **Table 1** and **Table 2** respectively.

Table 1: Cost summary table

Item	Baseline Value	Reference/Source	Variability Range
Surface Infrastructure: Roads	\$1,000,000/km x Distance to nearest road listed on national road network database	(Government of Canada & Natural Resources Canada, 2015; Morrison Hershfield Ltd., 2008)	\$10,000/km to \$1,500,000/km (1% baseline cost to 150% baseline cost)
Direct-use Heat: Insulated Pipelines	\$500,000/km x Distance to nearest customer to off-take heat energy	(Eastern Irrigation District, 2021)	Constant
Surface Infrastructure: Transmission Lines (120°C and 150°C scenarios only)	(\$720,000/km x Distance to nearest transmission line)	(Grunberg, 2021; Mines & U.S. Department of Energy's Geothermal Technologies Office, 2016)	\$7,200/km to \$1,080,000/km (1% baseline cost to 150% baseline cost)
Transmission Line Integration Costs (120°C and 150°C scenarios only)	\$200,000 (to account for engineering, load balancing, costs to integrate into existing transmission line)	(J. Marin, personal communication, March 29, 2022)	Constant
Electricity Equipment: Organic Rankine Cycle/Binary Turbines (120°C and 150°C scenarios only)	\$3,500/kW x Electrical output (dependent on flow rate)	(Holmes et al., 2022)	\$1,000/kW to \$5,000/kW
Facility Construction and Land Purchase Costs	\$3,000,000 (to account for permitting, lease acquisition, facility construction costs)	n/a	\$500,000 to \$10,000,000

Operational Expenses (OPEX) and Maintenance costs	\$200,000/year (40°C and 80°C scenarios) \$500,000/year (120°C and 150°C scenarios)	(U. S. Energy Information Administration, 2020)	\$100,000 to \$2,000,000
Drilling Costs	Derived from Alberta Modernized Royalty Framework Calculator + \$300/m for each m of Precambrian basement rock drilled through to reach desired geothermal resource temperature	(Government of Alberta, 2022a)	1% baseline cost to 150% baseline cost
Reservoir Stimulation	\$3 million per well pair (if desired resource temperature occurs in Precambrian basement rock) \$1.25 million per well pair (if desired resource temperature occurs in Western Canadian Sedimentary Basin)	(Lowry et al., 2017)	1% baseline cost to 150% baseline cost

Table 2: Revenue summary table

Item	Baseline Value	Reference/Source	Variability Range
Electricity (120°C and 150°C scenarios only)	\$90/MWh lifetime average power purchase agreement price Dependent on electricity output (estimated from GETEM as a function of flow rate) x 8760 x 95% capacity factor	(Mines & U.S. Department of Energy's Geothermal Technologies Office, 2016)	\$40/MWh to \$200/MWh
Direct-use Heating	\$9/GJ lifetime average value of heat energy above 20°C Dependent on flow rate, heat loss in transit to customer (assumed 1°C/km), annual portion of heat that can be sold (50%), annual performance decline (1%)	(Falchi et al., 2016; Ryan, 1981)	\$5/GJ to \$25/GJ Annual portion of heat sold varies from 1% to 100% Annual performance decline varies from 0%/year to 2%/year
Lithium	\$1/kg net value of lithium Dependent on flow rate, lithium concentration in the area, extraction efficiency (assumed to be 3%), annual performance decline (1%).	(Lopez et al., 2020)	\$0/kg to \$100/kg
Carbon Credits	\$50/ton net price of sequestered CO_2 Dependent on net price of sequestered CO_2 x the annual tons of CO_2 sequestered (0 tons/year)	(Government of Canada, 2022a)	\$0/ton to \$170/ton 0 tons per year to 2,000 tons per year

Economic factors were quantified and modelled such as drilling costs (dependent on rock type, depth to reach desired subsurface temperatures, and drilling efficiency), construction & installation costs, costs to develop required infrastructure to a project site, operational expenses, revenue from electricity (120°C and 150°C projects only), revenue from heat sold for direct-use heating, revenue from recoverable minerals from geofluids, and income derived from the value from sequestering carbon. The resulting model is an interactive, map-view display of how Alberta's geothermal viability picture changes under variable techno-economic conditions. For example, if a user was curious about how the estimated feasibility of a region changes with a 20% reduction in drilling costs, the model has the functionality to recalculate and display the map under those conditions.

Dollar values associated with each cost and revenue layer were assigned to each grid cell of the techno-economic map such that and lifetime costs lifetime revenues could be estimated, and a net present value (NPV) calculation could be made. The net present value was calculated by **Equation 1**:

$$NPV = \sum_{i}^{n} \frac{\boldsymbol{Annual\ Revenue_i}}{(\boldsymbol{1+r})^{\boldsymbol{i}}} - \boldsymbol{Initial\ Costs} \tag{1}$$

where n is the project lifetime (assumed to be 35 years), r is the discount rate (assumed to be 5%).

All up-front project costs were assumed to be overnight capital expenditures (even if construction would require more than one year, no discount rate was applied to construction costs). All future costs (operational expenses & maintenance) as well as all future revenues from sales of electricity, direct-use heat, lithium, or carbon sequestration credits were discounted at an annual rate of 5% for the project lifetime of 35 years. A rough estimate of performance decline was modelled via a user input parameter where the user could select one of 0%, 0.5%, 1%, or 2% for an annual performance decline value and the model estimated the year-over-year decline of the output of the project.

2.1 Project Costs

2.1.1 Drilling and completion costs

Expenses associated with drilling and well completion represent a large portion of a geothermal project's up-front costs. Drilling costs can also vary due to complexity in well design, a need to drill expensive horizontal laterals for a reservoir to be productive, or a requirement to drill through challenging geologic formations with slower penetration rates. As a result, it can be difficult to create a precise estimation of drilling costs for a potential geothermal project on a province-wide scale.

This research used geothermal gradient maps developed by Majorowicz (2018), to estimate depths to drill to various subsurface temperatures (40°C, 80°C, 120°C, and 150°C) across Alberta. The calculated depths to each resource temperature assumed a constant geothermal gradient as a function of depth. It should be noted that there is research from Alberta indicating that geothermal gradients can change as a function of depth, with one temperature/depth relationship above a geologic interface, and another temperature/depth relationship that changes by as much as 10°C/km beneath a geologic layer (Huang et al., 2021). As a result, the depths to 40°C, 80°C, 120°C, and 150°C as estimated by the constant geothermal gradient assumption may not be precisely accurate but represent modelled approximate depths to the temperatures of interest.

The Drilling and Completion Cost Allowance (C*) from the Modernized Royalty Framework formula developed by the Government of Alberta provides a relationship between well depths and completed well costs (Government of Alberta, 2022a). The Modernized Royalty Framework Drilling and Completion Cost Allowance (C*) is a proxy for completed well costs and is based on vertical depth, lateral length, and the amount of proppant placed; the relationship is expressed by **Equation 2** and **Equation 3**:

$$\boldsymbol{C^{*} = 0.82\,(1170\ \times (V - 249) + \big(3120(V - 2000)\big) + 800H + (0.6V\ \times 1.5P))} \quad (2)$$

for wells deeper than 2000m and:

$$\boldsymbol{C^{*} = 0.82(1170\ \times (V - 249) + 800H + (0.6V \times 1.5P)} \quad (3)$$

for wells shallower than 2000m. Where C* is the completed well cost ($), V is vertical depth of the well (m), H is the total horizontal lateral length of the well (m), and P is the amount of proppant placed (tons).

For this application, V was calculated from the depth to each of the subsurface temperatures of interest (40°C, 80°C, 120°C, and 150°C) across the province. These depths were derived from the Majorowicz (2018) geothermal gradient maps assuming a constant geothermal gradient with depth. All wells were assumed to have a constant lateral length: H = 500 m. All wells were assumed to have a constant amount of proppant placed: P = 10 tons of sand. Under these assumptions, a well drilled to a depth of 3 km would cost an estimated $5.5 million.

Recent data for drilling costs through crystalline basement rock in Alberta was unavailable, so assigning an appropriate cost premium that accounts for the slower rate of penetration (ROP) and shorter bit life associated with drilling through Precambrian rock is challenging. Beckers & Johnston (2022) estimated drilling costs for varied ROP at depth to be between 25 ft/hr and 75 ft/hr and drill bit life ranging between 50 hours and 150 hours led to drilling costs ranging between $147/m and $606/m. Geothermal drilling activities at the FORGE Geothermal project in Utah, report a drilling penetration rate of about 50 ft/hr and drill bit life of up to 25 hours (Winkler & Swearingen, 2021). With the range of values reported by Beckers & Johnston (2022) in mind, an additional cost of $300/m for each meter of Precambrian basement to be drilled through to reach the depth of the selected resource temperature. This means that for a well with a total depth of 3 km in the portion of a province where 1 km of Precambrian basement rock must be drilled through, the estimated baseline drilling cost would be $5.5 million as calculated by the Alberta Modernized Royalty Framework formula plus $300,000 to account for the slower drilling through crystalline basement rock, resulting in a total estimated drilling and completion cost for this scenario to be $5.8 million per well.

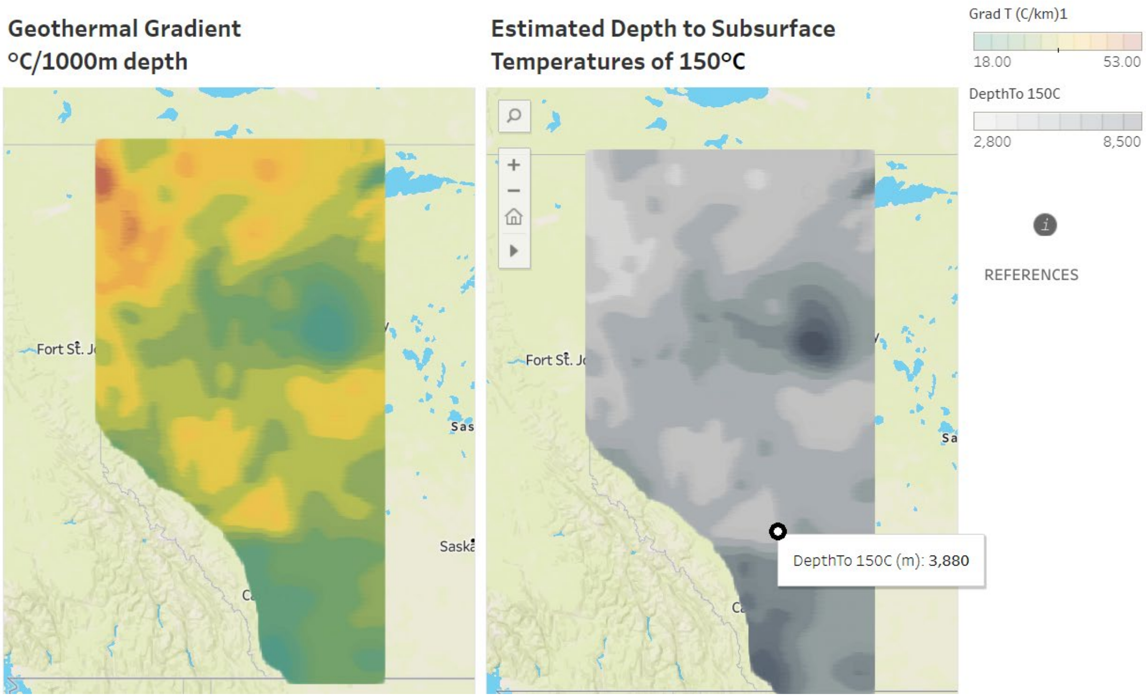

Figure 2: The geothermal gradient map developed by Majorowicz (2018) is displayed on the left: red-orange shaded areas represent regions where the geothermal gradient is approximately 40-53°C and blue-green shaded areas represent regions where the geothermal gradient is approximately 18-30°C. The estimated depth to the geothermal resource temperature of 150°C is displayed on the right. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

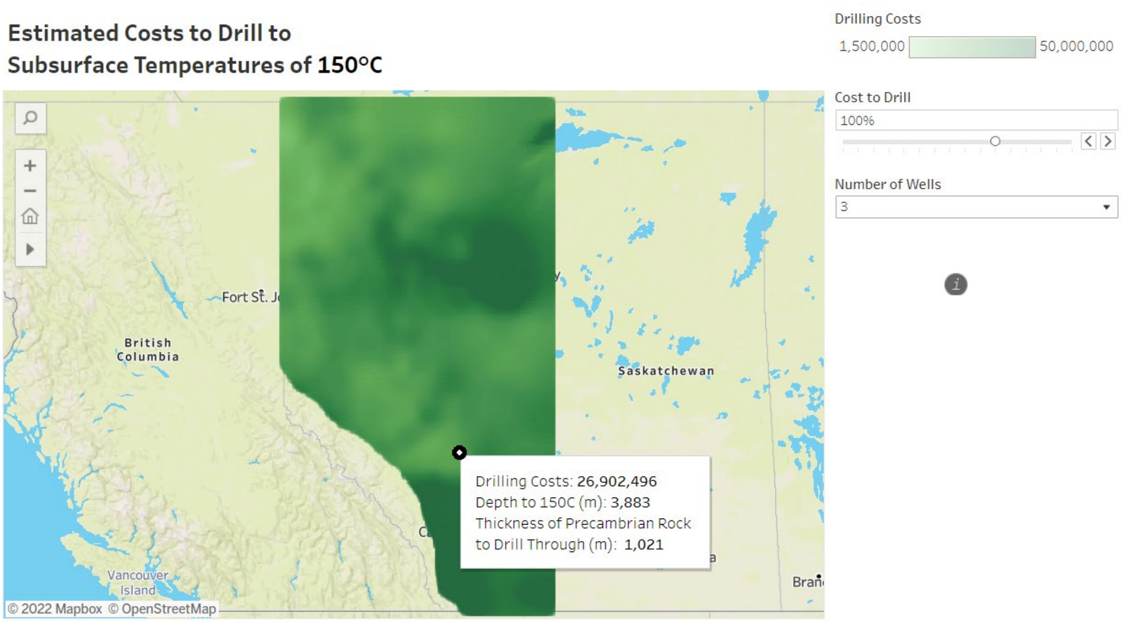

Figure 3: The Alberta Modernized Royalty Framework C* calculator was used to generate this cost to drill map. Darker green regions represent areas where it is more expensive to drill to reach depths where the geothermal resource temperature is 150°C, lighter green regions represent areas where it is cheaper to drill to reach depths to 150°C. A lateral length of 500 m and 10 tons of proppant were assumed for each well in the modelled scenarios. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

2.1.2 Reservoir stimulation costs

A geothermal reservoir without adequate porosity and permeability to flow at sufficient rates to produce heat or power must be enhanced or engineered with fractures and proppant so that there is enough connected pore space for fluids to flow through the high-temperature rock formations. Lowry et al. (2017) developed as a means of estimating reservoir stimulation costs as being $1.25 million multiplied by the number of well pairs for the geothermal project. This was the formula applied for reservoir stimulation costs for this project, however $1.25 million per injection well was used the baseline estimated cost where depth to the desired resource temperature was within the WCSB. A cost of $3 million per well pair was the baseline estimated cost when the depth to the desired resource temperature was in Precambrian basement rock. The extra cost is to account for the additional difficulty and complexity in engineering a geothermal fracture network within crystalline basement rock. Since no EGS projects have been developed using Alberta's Precambrian basement as a reservoir, estimating what the expected costs associated with fracturing crystalline basement in the area to engineer a reservoir is a challenge, so an adjustable modifier on the techno-economic model allows the user to adjust the reservoir stimulation costs between 150% of the baseline estimate ($1.875 million per well pair in the WCSB and $4.5 million per well pair in Precambrian basement) all the way down to 1% of the baseline estimate ($12,500 per well pair in the WCSB and $30,000 per well pair in Precambrian basement).

2.1.3 Construction and maintenance costs

As land purchase costs can vary drastically depending on where a geothermal project is sited, and the expense to construct a facility can also vary depending on costs of building materials, distance from a population center with construction workers, equipment/materials, and myriad other factors, facility construction and land purchase costs were defined as user inputs into the techno-economic model. The user-selected capital expenditure (CAPEX) values for land purchase and construction costs were factored into the NPV calculation with a default value of $2 million, with a user selecting values in $500,000 increments between $500,000 and $10 million. Costs for 120°C and 150°C combined heat + power projects also factor in pricing to purchase and install binary turbines to generate electricity realized on a $/kW basis ranging between $1000/kW to $5000/kW in $500/kW increments with a baseline value of $3000/kW.

Average annual operational expenses (OPEX) and annual maintenance costs were defined as user inputs into the techno-economic model's NPV calculation with an annual discount rate of 5% applied to future expenses over the lifetime of the project (assumed to be 35 years). The model's default value is $500,000 per year to account for average annual OPEX and maintenance costs, but the user can select values in $100,000 increments between $100,000 and $2 million.

To avoid the issue of the techno-economic model recommending a site where the grid cell happens to be on a permanent water body, a GIS shapefile of all the permanent waterbodies in Alberta was integrated into the model (Government of Alberta - Open Data & Environment and Parks, 2022). A value of $1 was added to CAPEX construction costs if the grid cell was not on a permanent waterbody, and a value of $100 million was added to construction costs if the grid cell was on a lake.

Although not factored into the model's economic assessments, Provincial and National Parks, Key Wildlife and Biodiversity Zones, Indigenous Communities/Indian Reserve Lands, and locations of recorded earthquakes between 2013-2017 with magnitude >1 were overlaid on the background map beneath the NPV model's grid cells (AltaLis, 2018; Government of Alberta, 2022b, 2022b; Government of Alberta Open Data, 2022; Stern et al., 2018). Parks, Biodiversity zones, Indigenous communities, or historical earthquakes in a region do not necessarily disqualify an area from a potential geothermal development, but special consideration may need to be given to ensure no negative impacts on treaty rights, induced seismicity, ecosystems, or protected species.

2.1.4 Infrastructure integration costs

For every 5 km x 5 km cell of the techno-economic model, the "spatial join" geoprocessing tool in ArcGIS Pro was used to calculate the Euclidian distance from each cell to the nearest roadway listed on the national road network (Government of Canada & Natural Resources Canada, 2015). This generated a "distance to road" raster layer map representing the straight-line distance from each grid cell of the model which was multiplied by $1 million/km to estimate the cost to build a road to each cell of the model. The value of value of $1 million/km was chosen as the baseline assumption since it is within the range of $720,00-$1.18 million per km of unpaved, surface treated roads described by (Morrison Hershfield Ltd., 2008). Obviously, the cost values estimated by this process are a rough approximation since roads are not built in perfectly straight lines following the path of least Euclidian distance to the nearest existing roadway, but given the scale and granularity of the model with each grid cell representing a 5 km x 5 km area that cannot resolve the detail on the quarter-section (800 m x 800 m or ½ mile x ½ mile) or section (1,600 m x 1,600 m or 1 mile x 1 mile) scale that many roadways are built on across Alberta, the "cost to road" values calculated for each grid cell on the model represent a rough approximation of the required cost to build a transportation infrastructure to the site of a potential geothermal project within the 5 km x 5 km area represented by the model's grid cell.

Portions of the province that are heavily forested, have dense spacing of water bodies, or ample muskeg (generally found in the northern part of Alberta) will likely be more expensive than $1 million/km to build, and portions of the province in the south where terrain is clear, dry, and flat may tend to be cheaper than $1 million/km. It is also feasible that some geothermal project sites would not require the construction of any new roadways if existing private roads to oil & gas sites not listed on the national road network can be utilized, or if a geothermal project proponent had an agreement with a local municipality that allowed the developer to avoid the costs associated with road building to a project site. As a result, a variable parameter was integrated into the model allowing the user to change the cost per km of constructed roadway, varying from $1,000/km (1% of the baseline cost estimate) up to $1.5 million/km (150% of the baseline cost estimate).

Transportation engineering and infrastructure planning is an entire field of professional practice and the challenge of precisely estimating costs to link a possible geothermal site across the province to the existing infrastructure network is more complex than the above-described approximation. However, given the level of granular detail that is feasible for a provincial-scale model of this type, the scope of this research project, and the goal of the techno-economic model being to provide a preliminary approximation of which areas in Alberta may be best-suited to the economic development of geothermal energy projects, the $/km estimation provides an introductory idea of which regions can be linked to the existing road network inexpensively, and which portions of the province would be more expensive.

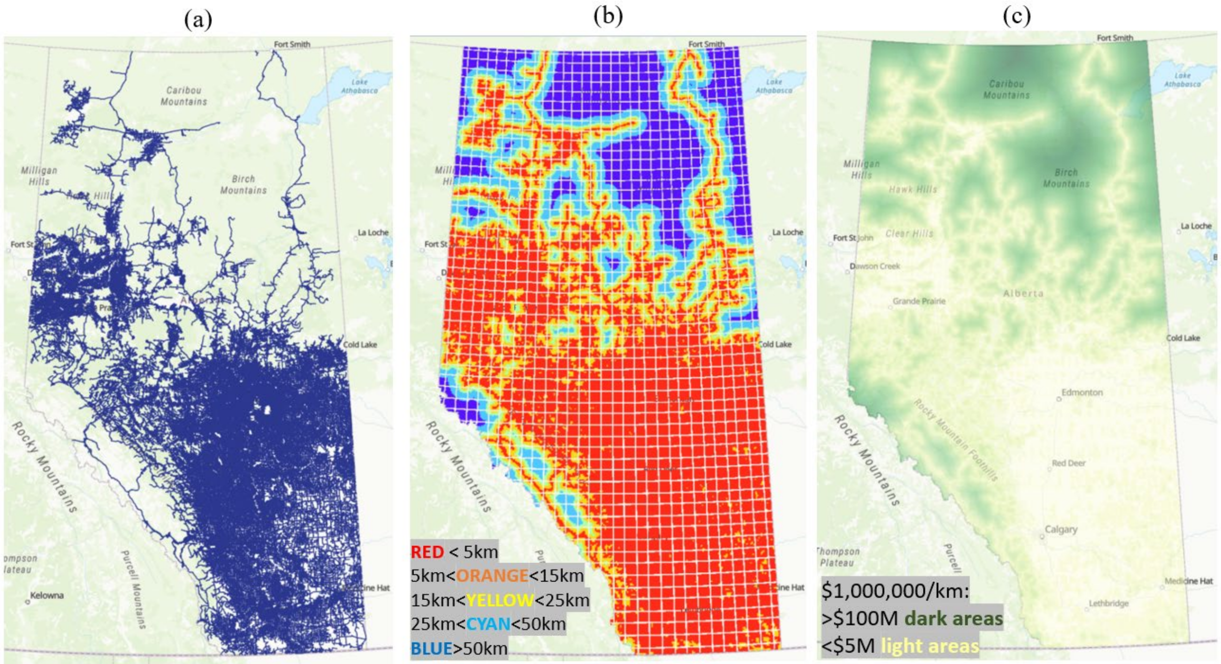

Figure 4:(a) Alberta roads as listed on the National Road Network (Government of Canada & Natural Resources Canada, 2015)
(b) Geometric distance from each 5 km x 5 km grid cell of the model to the nearest road listed on the National Road Network
(c) Estimated cost to build a road for each 5 km x 5 km grid cell of the model using a rice of $1 million/km. Darker green regions represent areas where it is more expensive to build a roadway, lighter green regions represent areas where it is cheaper to build a road.

For the 120°C and 150°C resource temperature projects where heat and electricity are produced, a similar approach was followed with the locations of existing transmission lines derived from the Cartofact database (Grunberg, 2021), and a variable cost/km value. Costs for recently completed transmission projects in Alberta vary between $1.6 million per kilometre and $6.6 million per kilometre (Transmission Facilities Cost Monitoring Committee, 2015), while the United States Office of Energy Efficiency & Renewable Energy's Geothermal Electricity Technology Evaluation Model (GETEM) uses $1.15 million dollars/mile ($720,000 per kilometre) as a default estimate (Mines & U.S. Department of Energy's Geothermal Technologies Office, 2016). This research project used the GETEM default value of $720,000/km for construction of transmission lines to a potential project as the baseline estimate. A variable parameter was integrated into the model allowing the user to change the cost per km of a transmission line, varying from $7,000/km (1% of the baseline cost estimate) up to $1.08 million/km (150% of the baseline cost estimate). A lump sum cost of $200,000 was applied for every grid cell to account for load balancing and engineering fees associated with linking into the transmission grid (J. Marin, personal communication, March 29, 2022).

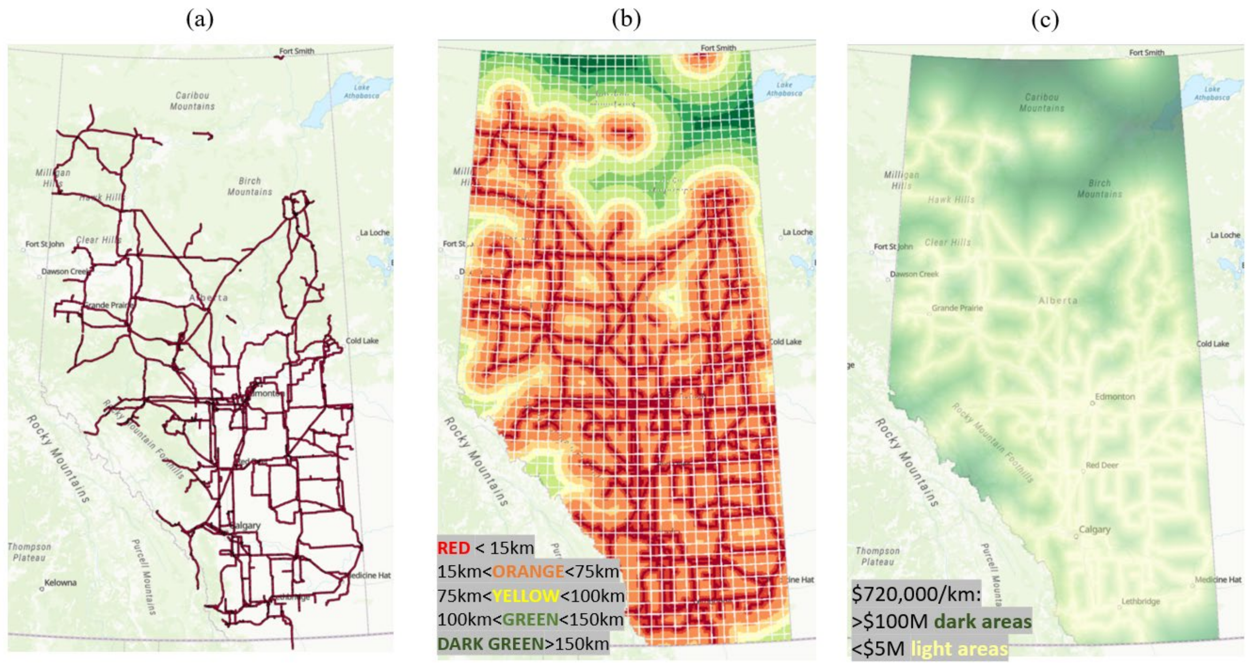

Figure 5:(a) Alberta transmission lines (Grunberg, 2021),
(b) Geometric distance from each 5 km x 5 km grid cell of the model to the nearest transmission line,
(c) Estimated cost to build a transmission line for each 5 km x 5 km grid cell on the model using a price of $720,000/km

Alberta's cold climate creates a significant demand for heat energy, but due to heat loss when transporting hot fluids, a potential geothermal project must be located reasonably close to a potential customer to offtake that heat. As a result, developing a map for potential clients who may be willing to make use of a geothermal project's heat is critical when considering the map of potential geothermal projects across the province of Alberta.

The customer map was made by taking light pollution data from the World Atlas of Artificial Night Sky Brightness by Falchi et al. (2016), and combining that map with the location of Alberta greenhouse gas emitting facilities as reported by the Government of Canada (2022). The rationale was that if a population centre was large enough to generate light pollution above a threshold value, then the area may have commercial or residential facilities large enough to utilize geothermal heat for space or hot water heating applications. Similarly, if a facility was emitting CO_2, then it was likely burning hydrocarbons, and therefore may have use for hot water to preheat boilers or facilitate some industrial process. Combining these 2 data sets serves as a proxy map for customers who may need hot fluids for either residential, commercial, or industrial processes.

Costs associated with construction of buried and insulated pipelines to transport hot fluids were estimated by proxy by evaluating publicly available project cost data for irrigation lines (Eastern Irrigation District, 2021). These pipes would have large enough diameters to handle high-flow rates associated with geothermal projects and given that they are constructed from appropriate insulating material or sheathing, should be able to transport hot fluids distances less than 20 km so that the energy could be utilized for direct-use heating applications. Project costs for 10 recent irrigation lines were evaluated and the mean cost per kilometer of these projects is $483,810/km which may provide a reasonable baseline estimate for constructing infrastructure for projects that are not co-located with a customer to off-take excess heat energy**.** As a result, a cost of \$500,000/km was used to estimate costs associated with a geothermal hot water pipeline to deliver heat to customers. As with the assumptions related to road and transmission line construction, complications associated with pipeline routing could not be reasonably factored into this model, so a straight line following the shortest geometric distance between project and customer was assumed for estimated costs to build infrastructure to deliver heat. The process of generating the map estimating the locations of customers for direct-use heating applications is shown below on **Figure 6.**

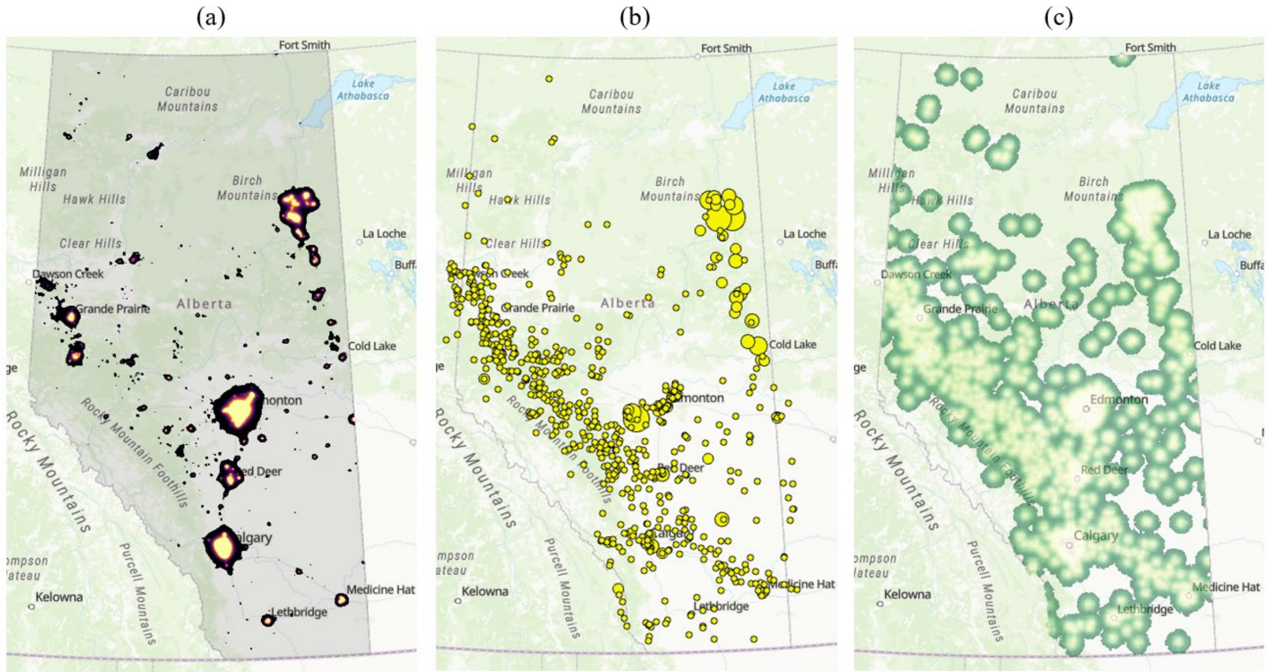

Figure 6:(a) Light pollution data from Falchi et al (2016)
(b) Locations of greenhouse gas emitting facilities as reported by the Government of Canada (2022)
(c) Distance to potential customer map derived from combining both data sets displayed on (a) and (b). The maximum radius around each customer was limited to 20 km. Costs for building insulated water lines to deliver heat from a potential project site to a customer were estimated at \$500,000/km based on costs for irrigation projects; dark green represents costs approaching \$10 million (Eastern Irrigation District, 2021)

A heat loss rate of 1°C/km was used to approximate temperature losses of hot fluids in transit from a geothermal project site to a potential customer (Ryan, 1981). As a result, the farther a project was from a potential customer, the less heat that it could effectively deliver. The maximum distance between a grid cell representing a customer and a grid cell representing a potential project site was limited to 20 km. As with the assumptions related to road and transmission line construction, complications associated with pipeline routing could not be reasonably factored into this model, so a straight line following the shortest geometric distance between project and customer was assumed for estimated costs to build infrastructure to deliver heat.

2.1.5 Total project costs

Estimated total project costs are mapped on **Figure 7** with interactive sliders allowing the user to adjust variables to visualize how project costs change in a particular region if a project developer was not required to pay for the cost of a road or a transmission line to a project site.

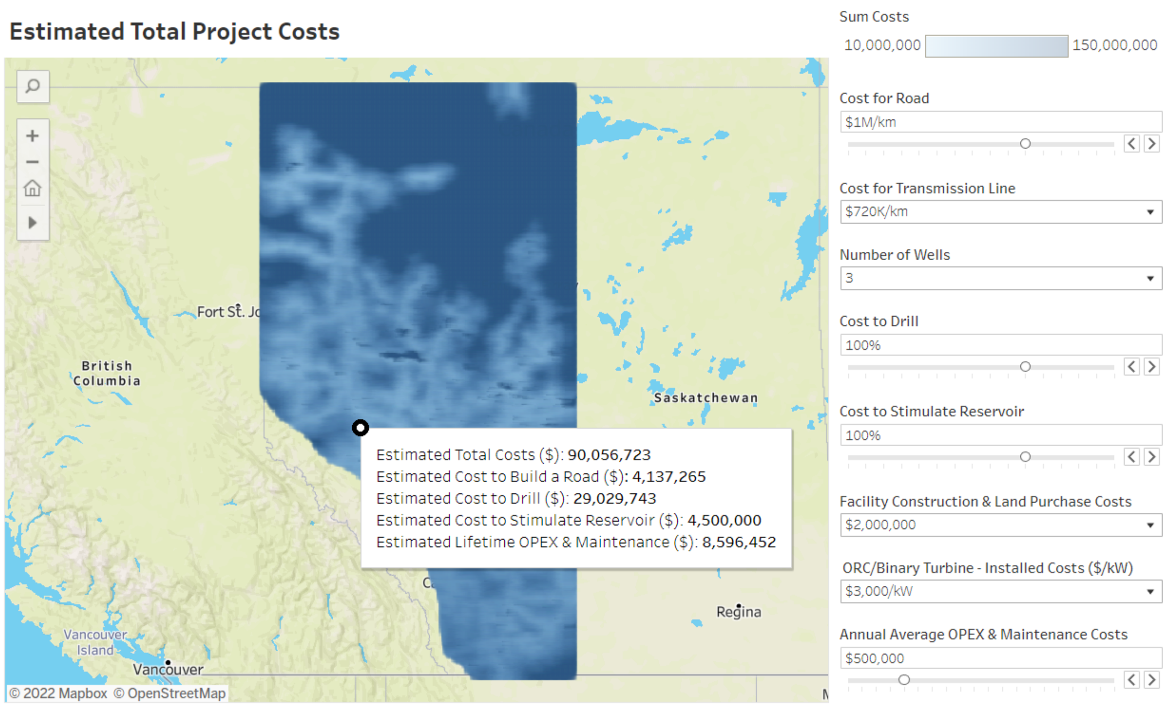

Figure 7:Total estimated project cost map for a 150°C project. Areas where it is cheaper to develop a project are shown in light blue (along existing infrastructure corridors) and areas where it is estimated to be more expensive are shown in dark blue. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

2.2 Project Revenues

2.2.1 Electricity

Estimating the potential electrical output from geothermal projects with reservoir temperatures of 120°C and 150°C using a tool such as the Geothermal Electricity Technology Evaluation Model (GETEM) is a means of both estimating the net power output and the costs associated with buying and installing the turbines for these hypothetical projects. To this end, GETEM was run specifying an EGS project with varying flow rates and number of wells scenarios and the net power output from the system was recorded. Regression analysis was completed using the 2nd order polynomial curve fitting function to generate a formula for the techno-economic model where a user could input the number of wells and flow rate for a resource temperature of 120°C or 150°C and the model could return an estimate of the net power output from the facility. Results of the power output estimation given variable flow rates and numbers of wells are shown below on **Figure 8** (120°C) and **Figure 9** (150°C).

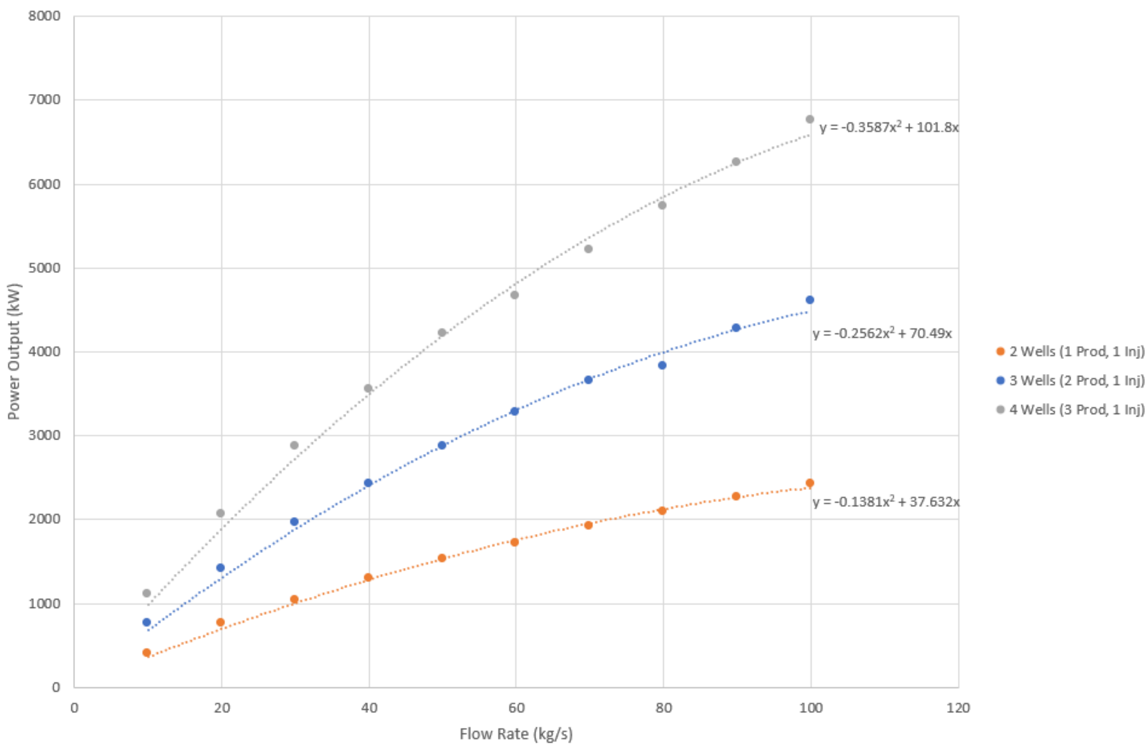

Figure 8:Estimated net electricity output for an EGS project with a 120°C resource temperature flowing at variable rates. These output estimates were generated from GETEM developed by Mines & U.S. Office of Energy Efficiency & Renewable Energy (2016).

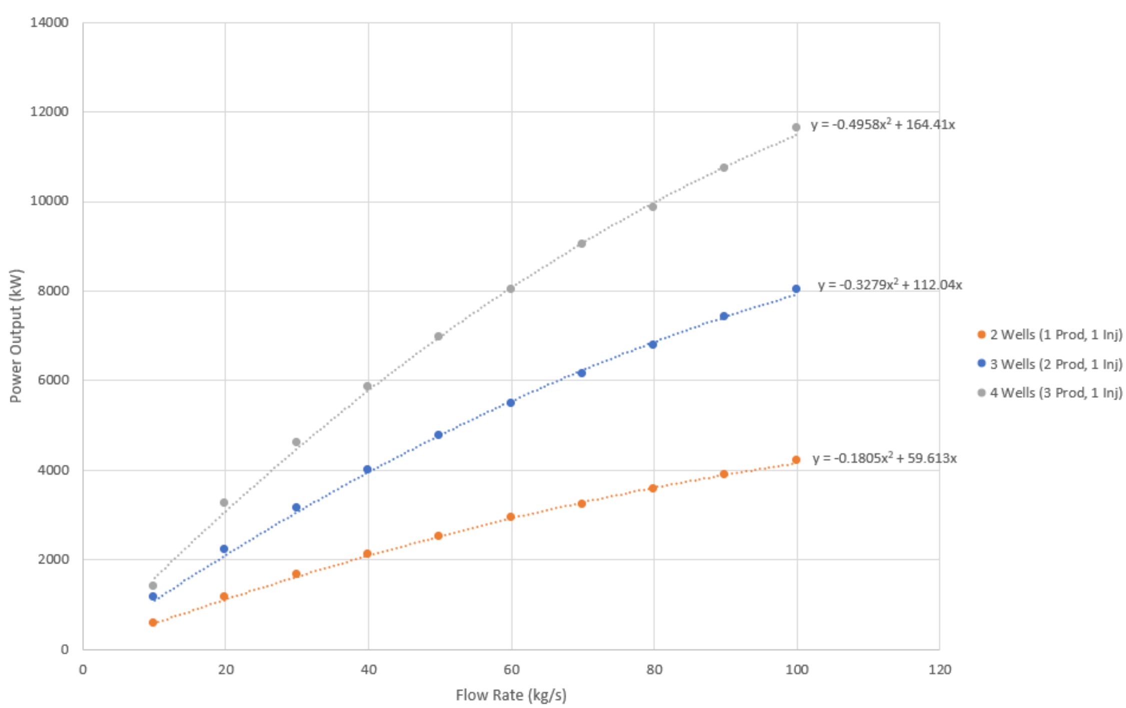

Figure 9:Estimated net electricity output for an EGS project with a 150°C resource temperature flowing at variable rates. These output estimates were generated from GETEM developed by Mines & U.S. Office of Energy Efficiency & Renewable Energy (2016).

There is a very important caveat to be considered with this approach: there is no guarantee that a given formation can flow at the user-specified rate without substantial decline in the reservoir's thermal performance, but instead, the model states that if a reservoir could be engineered to flow at this rate and maintain stable temperatures, then it would generate the estimated output. For these models, flow rate is a parameter that the user manipulates to gain an understanding of what conditions need to be in place for a potential project to be economically viable; flow rate is not an estimation based on subsurface geologic conditions. Gathering the kind of information required to estimate the maximum flow rate that could be reasonably expected in specific geologic formations around the province added complexity that was beyond the scope of this research project. Estimating the physical limitations of the maximum possible flow rates associated with a specific reservoir requires detailed and site-specific porosity, permeability, fracture mechanics, and specific heat capacity data for the geologic formation and cannot be estimated on provincial scale maps without significantly more data informing this model's calculations. Instead, by making flow rate a variable parameter, the model aims to give the user an understanding of the approximate numbers they would need to achieve for a project to be profitable. The estimated flow rate needed out of a reservoir to generate the output required for a profitable project serves as a guideline for more detailed site-specific follow-up studies and reservoir engineering discussions to determine if the required flow rates are attainable in the region of interest.

Revenues associated with electricity sales over the lifetime of the project were realized through a user-selected lifetime average power purchase agreement (PPA) price in the form of $/MWh. The selectable range for PPA prices ranged between $40/MWh and $200/MWh. A capacity factor for the facility was assumed to be 95%. Future revenues from the sale of electricity were discounted at an annual rate of 5% and the lifetime of the project was assumed to be 35 years.

The interactive maps also have a simple feature to model annual performance decline of a project. The user can select values to approximate the year-over-year decline of a project. The output of the project was modelled by the relationship shown in **Equation 4**:

$$Total\ Modelled\ Output = \sum_{i}^{n} Year\ 1\ Output\ (1-d)^{i} \tag{4}$$

where n is the project lifetime (35 years), and d is the annual performance decline (either 0%, 0.5%, 1%, or 2%) as selected by the user.

2.2.2 Direct-use heat

The temperature of the geothermal fluids at surface was approximated from up-hole heat loss estimations provided by the GETEM user manual (Mines & U.S. Office of Energy Efficiency & Renewable Energy, 2016). For 120°C and 150°C projects, the amount of heat available for direct-use applications was calculated based on the approximate temperature of a fluid after running through an ORC/binary turbine system with efficiency in the range of 10%-12%. These numbers are summarized in **Table 3** below.

Table 3: Summary of values used for direct-use heating applications

Resource Temperature	Estimated Fluid Temperature into ORC Turbine	Estimated Fluid Temperature out of ORC Turbine	Fluid Temperature Available for Delivery to Customers	ΔT Above Ambient Temperature (20°C) Available for Customers	Assumed Customer Heat Exchanger Efficiency
40°C	n/a	n/a	39°C	19°C	60%
80°C	n/a	n/a	79°C	59°C	60%
120°C	117°C	50°C	50°C	30°C	60%
150°C	147°C	80°C	80°C	50°C	60%

The above values were programmed into the interactive model accompanying the user-defined flow rate parameter that was the same parameter that was linked to estimates for electricity output described in **Section 2.2.1**. Estimated heat energy per second (Q, measured in kW) delivered to potential customers was estimated by **Equation 5**

$$\boldsymbol{Q = mc(\Delta T - T_{Losses})e_{HX}} \tag{5}$$

where m is the flow rate defined by the user (kg/s), c is the specific heat capacity of the fluid (assumed to be 4.2 kJ/kg°C), ΔT is the temperature above ambient shown in **Table 2**, T_{Losses} are accounted for at a rate of 1°C/km for the distance high temperature geofluids are transported from each grid cell in the model to the assumed customers described in **Section 2.1.4**, and e_{HX} is the efficiency of the customer's on-site heat-exchanger (assumed to be 60%). To better compare heat energy delivered to customers with natural gas (the dominant source of heat energy in Alberta), the output from **Equation 5** was converted to gigajoules of energy (GJ) by multiplying by the number of hours the facility was expected to be in operation per year (Q x 8760hrs/year x 95% capacity factor) to get a value for the kWh per year which was in turn multiplied by a conversion factor (1 GJ = 277.778 kWh) to estimate the amount of heat energy per year that could be delivered to a customer. Annual performance decline of the geothermal heat output was modelled as per **Equation 4** following a user-defined annual performance decline value of either 0%, 0.5%, 1%, or 2%.

The amount of heat energy per year that could be delivered to a customer was then multiplied by a user-defined parameter indicating the portion of heat that could be sold to a customer (1%-100%). The intention of this parameter was to provide the model's user with the ability to differentiate between space heating applications, which may only require heat delivered 40-60% of the year during the colder months, and hot water heating or industrial applications which may require a more constant annual supply of heat energy. The model built for this research project estimated that the amount of heat energy delivered by a 3-well EGS project with resource temperature of 80°C project flowing at 50 kg/s in the Edmonton region where 50% of the heat could be sold to customers would be approximately 140,000 GJ/year (year 1). This estimation is comparable to techno-economic estimates made by Hofmann et al. (2014) who projected that a 3-well direct-use heating facility flowing at 50 l/s operating from the Cambrian Basal Sandstone unit (estimated resource temperature 90°C) could generate 136,666 GJ per year of energy for a 30-year lifespan.

The above estimations were factored into the techno-economic model using a user-defined input for the lifetime average dollar value of this heat energy on a \$/GJ basis. The lifetime average value for heat above 20°C that the user can select ranges between \$5/GJ and \$25/GJ and can be selected at \$0.50 increments. The project's annual delivered heat output is multiplied by this price per GJ to estimate annual revenues associated with selling direct-use heat. As with revenues from electricity described in **Section 2.2.1**, a user-defined performance decline rate between 0% per year and 2% per year was applied to the project's estimated output and an annual discount rate of 5% was applied to future revenues over the project's assumed 35-year lifetime.

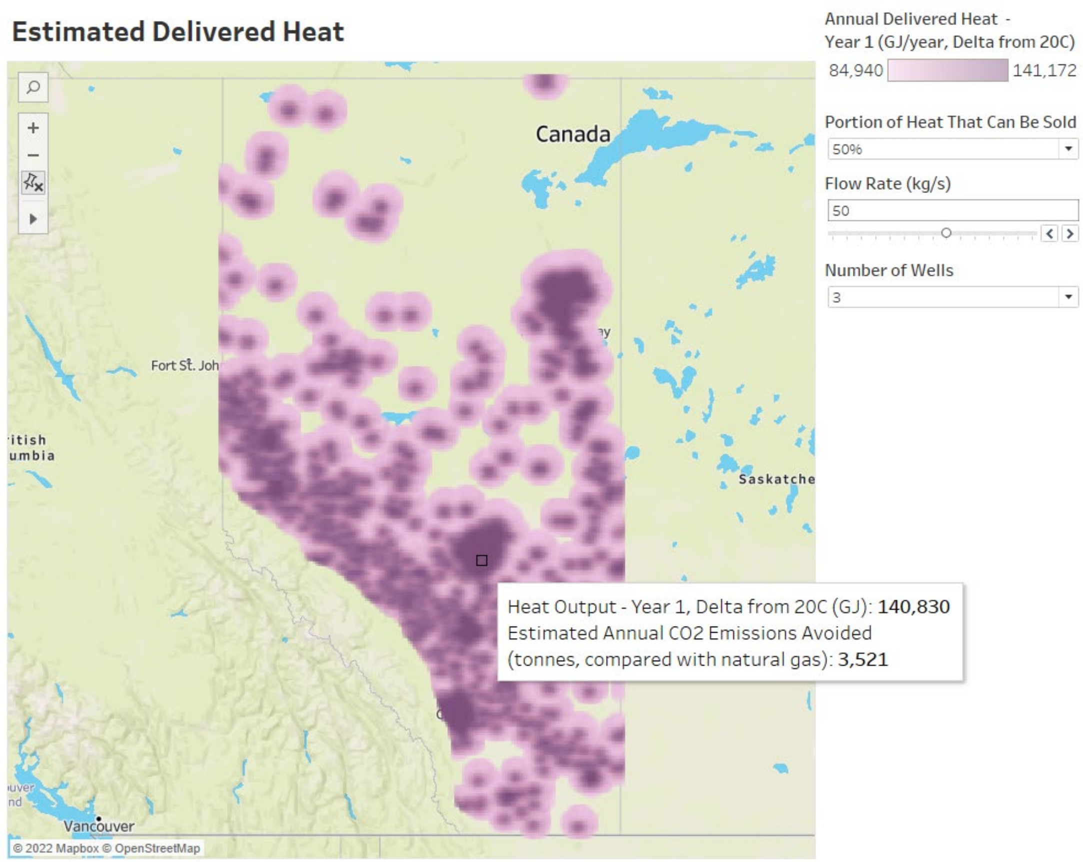

Figure 10: Estimated heat energy delivered above ambient temperature (20°C) for an 80°C geothermal resource temperature. Darker purple regions deliver more heat to customers, light purple regions deliver less heat due to losses in transportation from a project to the assumed customer derived from the maps show on Figure 7. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

2.2.3 Carbon credits

As Canada's federal carbon tax escalates to \$170/ton by 2030 (Government of Canada, 2021), the market value of carbon removal credits associated with sequestration is expected to grow to a price ceiling of $170/ton (Sullivan et al., 2021). Since EGS projects may have the potential to sequester CO_2 in subsurface reservoirs, the prospect of collecting as much as $170 for every ton of sequestered CO_2 may present an interesting economic opportunity for a geothermal project. Due to the complexity of the reservoir engineering and geoscience problem in the emerging field of CO_2 sequestration, this research project could not model or make estimations regarding which of Alberta's geothermal resources may be well-suited to CO_2 sequestration, or what amounts of CO_2 could be sequestered in given reservoir, but the economics of sequestration were roughly approximated into the techno-economic model.

This approximation was calculated through 2 user-defined inputs: net price of sequestered CO_2 and annual tons of CO_2 sequestered. The model's user can select an annual amount of CO_2 sequestered (ranging between 0 and 2000 tons/year in 100 ton/year increments) and can also select a net price ($/ton) for the value of sequestered CO_2 ranging in $5/ton increments between $0/ton (baseline value), and $170/ton. The idea is that the user should select a price for sequestered carbon that accounts for the overhead costs associated with CO_2 sequestration realized on a $/ton basis. The selected price should be the market value of sequestered carbon (projected to be $170/ton in Canada after 2030) minus the overhead expenses per ton of CO_2 injected into the subsurface. Since the economics of carbon sequestration projects are changing rapidly with the commercialization of sequestration technologies and the implementation of carbon pricing, it was difficult to make an appropriate estimate about what the expected profit per ton of carbon sequestered may be, so this value was left as an input so the user could get an understanding of what annual amount of CO_2 would need to be sequestered and what the net revenue per ton the project would need to realize for a theoretical EGS project in a region to become economically viable. As with annual revenues from electricity or heat sales, a project's future income was discounted using an annual discount rate of 5% over the project's assumed 35-year lifetime.

Similar caveats described in **Section 2.2.1** regarding flow rates apply in the case of estimating revenue from carbon sequestration: there is no guarantee that a given reservoir can sequester the user-specified amounts of CO_2 without risking over-pressurizing the reservoir or jeopardizing the project's performance, but instead, the model states that if a geothermal project's reservoir could be engineered to sequester this amount of CO_2 per year and collect the specified net price per ton of CO, then it would have the calculated impact on a potential project's economic viability.

Although not factored into the economic model, avoided emissions from electricity or heat produced by a hypothetical geothermal project were calculated based on the comparison to Alberta's electricity grid using the 2022 emissions factor of 0.52 tonsCO_2/MWh (Sadikman et al., 2022), and heat emissions from natural gas of 50 kgCO_2/GJ of heat energy from the combustion of natural gas (United States Environmental Protection Agency, 2022). For every MWh of electricity that a geothermal project could generate in 2022, the project would have access to 0.52 tons worth of avoided emissions carbon credits either on a compliance or voluntary carbon market; similarly, for every 100 GJ of heat that a project could deliver to a customer, 5000 kg (5 tons) worth of avoided CO_2 emissions credits would be available to the project operator. Revenues associated with these avoided emissions credits were not modelled due to the rapidly changing market for credits, and the progressive reduction of emissions associated with Alberta's electricity grid as the province brings more sources of low-carbon electricity online.

2.2.4 Lithium extraction

Alberta has a robust public data set showing the locations, depths, and concentrations of lithium in subsurface water formations. As a result, the data set developed by Lopez et al. (2020) and published by the Alberta Energy Regulator formed the basis for evaluating the possibility of adding lithium extraction at a potential EGS facility. For this research project, the GIS-compatible lithium concentration data from Lopez et al (2020) was filtered such that sample depths that were only within the range of ±10% of the estimated depth of the geothermal resource temperature were used for each scenario's analysis.

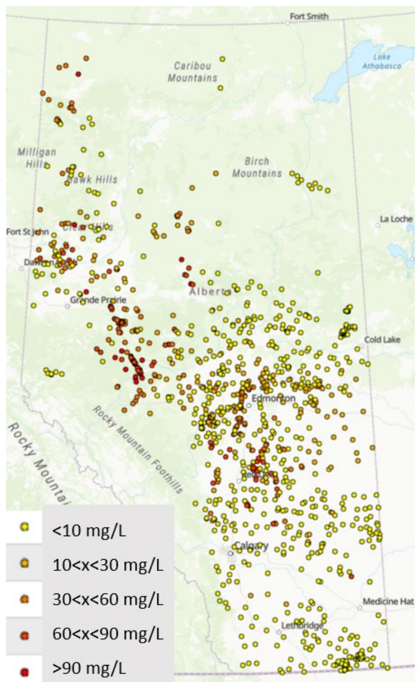

Figure 11: Locations and concentrations of lithium from groundwater sample data from Lopez et al (2020)

Point-source groundwater sample data was spatially interpolated and extended beyond the exact coordinates of the sample location using ArcGIS Pro's "Simple Kriging" geoprocessing tool with a specified search radius of 10 km. The Kriging algorithm is a geostatistical process that performs a linear interpolation between closely spaced data points and effectively turns a point into a circular surface on a map for data points where there are no other points within the algorithm's search radius (ESRI, 2022). The Kriging process smooths lithium concentration values between points and does not consider the possibility of discontinuities between concentrations points due to faulting or other geologic complexities. As such it represents a general approximation of subsurface lithium concentrations in a region. Areas with no data were assumed to have a lithium concentration of 0 mg/L.

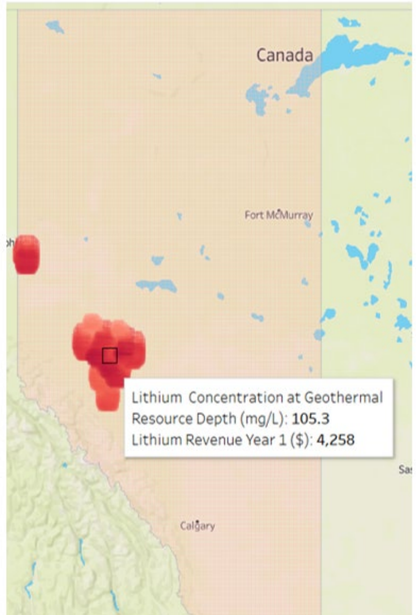

Figure 12: Lithium concentration data from Lopez et al (2020) was filtered so that sample depths were only within the range of ±10% of the estimated depth of the 120°C geothermal resource temperature. Point values were gridded using ArcGIS Pro "Simple Kriging" geoprocessing tool with a search radius of 10 km surrounding each point. The displayed year 1 revenue was estimated using a net lithium price of $1/kg. Basemaps were developed by the author with Mapbox (2022); data analytics completed via Tableau (2022).

Lithium revenue was calculated using **Equation 5** using the spatially interpolated groundwater lithium concentration values from the Lopez et al (2020) data.

$$\boldsymbol{LR_{Year1}} \frac{\boldsymbol{C \times F \times e \times N \times (60 \times 60 \times 24 \times 365 \times 0.95)}}{\boldsymbol{1{,}000{,}000}} \tag{6}$$

where LR_{Year1} is lithium revenue in the first year of operation (before performance decline of the asset is accounted for), C is the concentration of lithium in the geofluid (mg/L), F is the user-defined mass flow rate (kg/sec) used in heat & power calculations, e is the extraction efficiency of the mineral separation module (assumed to be 3% for this study), and N is the net price of lithium per kilogram (a user-defined value ranging between $0 and $100). A 95% capacity factor is assumed for this calculation.

Extraction efficiencies for lithium from geofluids can be as high as 70% (Flexer et al., 2018), however this extraction rate would only be achieved under ideal conditions for flow, temperature, pH, presence of other dissolved solids, and several other complicating factors. As geothermal reservoirs flow at high rates and high temperatures which may not be ideal conditions for lithium extraction, and since there is the possibility that injected fluids for well-stimulation would dilute the measured concentrations of geofluids, and in the interest of modelling the gradual depletion of the lithium resource over the 35-year lifetime of the project, an extraction rate of 3% was assumed.

2.2.5 Total project revenues

A sample image showing a total project revenue map on **Figure 13** with interactive sliders allowing the user to adjust variables to visualize how project revenues change in a particular region given variable price or flow conditions.

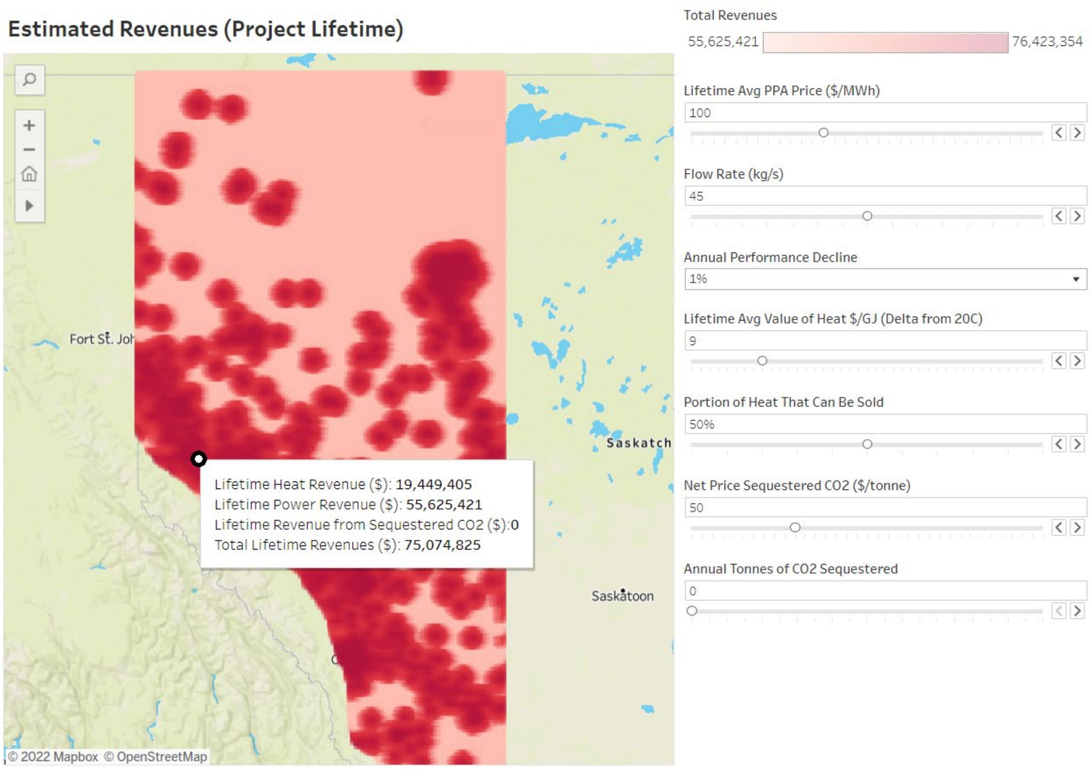

Figure 13:Total estimated revenue map for a 150°C project. Areas where lifetime revenues are higher (where electricity and heat energy can be sold) are shown in dark red compared to areas where lifetime revenues are lower in light red. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

2.3 Net present value

Lifetime cost maps (as shown on **Figure 7**) and lifetime revenue maps (as shown on **Figure 13**) were used to complete a Net Present Value (NPV) calculation as shown in **Equation 1.** By combining the lifetime discounted revenues with the lifetime costs of the project, an interactive NPV map is generated which displays the estimated economic viability of a region under variable conditions.

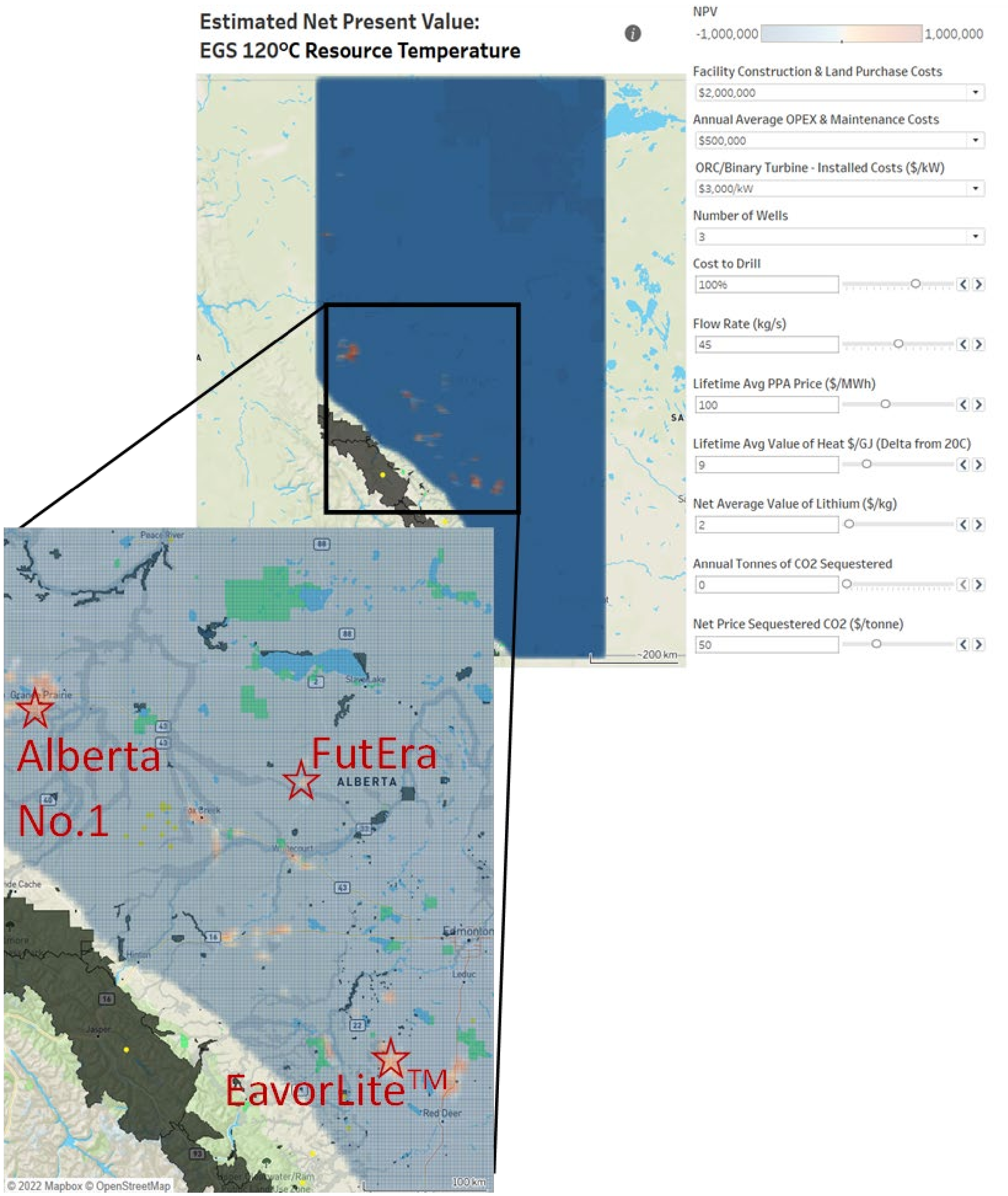

Figure 14: NPV map showing where 120°C projects were modelled to be economic (red cells) given user-defined variables such as power purchase agreement price ($/MWh), flow rate (kg/s), cost to drill, and average value of heat ($/GJ). Some of the first areas modelled to have a positive NPV for the 120°C scenario correspond to regions where geothermal developments are planned or operating (indicated with the red stars). On the inset map, Parks and Protected Areas are shaded with dark grey, Key Wildlife and Biodiversity Zones are shaded in light grey, Recorded Earthquakes (greater than magnitude 1) are indicated with yellow points, and Indigenous Communities/Indian Reserve Lands are green areas. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

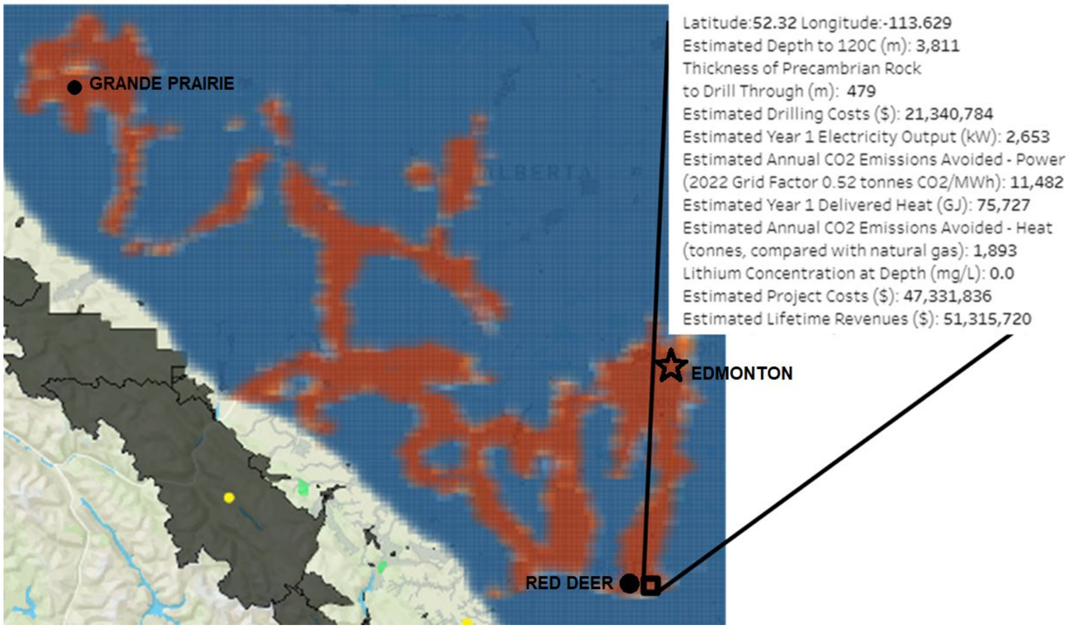

Figure 15: The NPV map for approximately the same portion of Alberta as the inset map on Figure 14 under the same techno-economic conditions but with a 30% reduction in drilling costs, a net price of $50/kg of lithium, and annual CO_2 sequestration of 1,500 tons with net revenue of $100/ton. Basemaps were developed with Mapbox (2022); data analytics completed via Tableau (2022).

3. Conclusion

The goal of this research was to create an interactive map that integrated multiple layers of information into an estimate showing which areas in the province of Alberta are best suited to developing EGS projects economically. Scenarios for geothermal projects with resource temperature depths of 40°C, 80°C, 120°C, and 150°C were modelled. The interactive map set can be found here: https://public.tableau.com/app/profile/gordon.brasnett

Some of the key findings from this project are as follows:

- The locations with the highest geothermal gradients in Alberta do not necessarily correlate with the locations of the most economically viable projects
    - Economically favorable locations for geothermal project development generally occurred in the Western portion of the province where Precambrian basement rock is deepest and along existing infrastructure corridors near population centers or industrial facilities to off-take heat energy
- A project's economic feasibility is heavily dependent on a geothermal reservoir's flow rate, costs to drill, costs to build surface infrastructure (roads or transmission lines), and ability to sell heat to nearby customers for direct-use applications
- The interactive model shows multiple pathways to a positive NPV in most regions across the province through variable conditions (e.g., increased flow rates from the geothermal

reservoir, drilling cost reductions, or if a project proponent is only required to pay a portion of the costs to build infrastructure to a development)

- A description of the locations of the first areas to achieve a positive NPV and notes summarizing the scenarios leading to these conditions are listed on **Table 4**
- Reducing drilling costs from the baseline scenarios described in **Table 4** expands the number of economically viable sites across the province
    - A 20% reduction in estimated drilling costs results in approximately 30% more locations across the province with a positive NPV (40°C resource temperature scenario)
    - A 20% reduction in estimated drilling costs results in approximately 300% more locations across the province with a positive NPV (80°C resource temperature scenario)
    - A 20% reduction in estimated drilling costs results in approximately 150% more locations across the province with a positive NPV (120°C resource temperature scenario)
    - A 20% reduction in estimated drilling costs results in approximately 300% more locations across the province with a positive NPV (150°C resource temperature scenario)

Table 4: Locations of first positive NPV projects

Resource Temperature	Area	Flow Rate (kg/s) [Assumed Portion of Heat Sold: 50%]	Price of Heat ($/GJ)	Price of Power ($/MWh)	Notes:
40°C	Grande Prairie, Lacombe	45	11	n/a	3 wells, $200,000/year OPEX, 1% annual performance decline
80°C	Grande Prairie, Fox Creek, Lacombe, Ponoka	45	8.5	n/a	3 wells, $200,000/year OPEX, 1% annual performance decline
120°C	Grande Prairie, Fox Creek, North of Chinchaga Provincial Park, East of Edson, Lacombe, Ponoka, West of Thorsby, Rimbey	45	8.5	90	3 wells, $500,000/year OPEX, 1% annual performance decline
150°C	East of High Level, North of Chinchaga Provincial Park, Grande Prairie, Fox Creek, Whitecourt, Swan Hills, Leduc, O'Chise Indian Reserve, Northwest of Rimbey	40	7	85	3 wells, $500,00/year OPEX, 1% annual performance decline

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