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Performance Evaluation and Costs of a Combined Ground Source Heat Pump and Solar Photovoltaic Storage System in an Extreme Cold Climate

June 2023

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Performance Evaluation and Costs of a Combined Ground Source Heat Pump and Solar Photovoltaic Storage System in an Extreme Cold Climate

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List of Abbreviations and Acronyms

Btu	British thermal unit
Btu/h	British thermal unit per hour
COP	coefficient of performance
DOE	U.S. Department of Energy
FAA	Federal Aviation Administration
GSHP	ground source heat pump
IRR	internal rate of return
kBtu	thousand British thermal units
kW	kilowatt
kWh	kilowatt-hour
METAR	meteorological terminal air report
NPV	net present value
NREL	National Renewable Energy Laboratory
PCE	Power Cost Equalization
PP	payback period
PV	photovoltaic
RACEE	Remote Alaska Communities Energy Efficiency competition

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Executive Summary

This report outlines the effectiveness and economics of a ground source heat pump (GSHP) system installed together with solar photovoltaic (PV) panels and a battery storage system in a local community building situated in a cold climate. The community building is a tribal building located in Ruby, Alaska. Shortly after the tribal building was built and occupied, solar panels and GSHP systems were added to it by a project managed by the City of Ruby, in collaboration with the tribe. Power from solar panels is used within the building, and is supplemented by electricity purchased from the local community microgrid. A GSHP was commissioned three years after the building was occupied, and supplements the heat generated by a boiler for both heat and domestic hot water.

Data collected over the 2021–2022 heating season show that the heat pump provided heat to the building about 19% of the time, with an average coefficient of performance (COP) of 2.68, ranging from below 2.5 in winter to above 3.0 in summer. The solar panels provided 4,700 kilowatt-hours (kWh) of power used within the building and an additional 2,900 kWh exported to the microgrid. The solar-produced power used within the building nearly offsets the estimated annual electrical draw of the heat pump of 5,700 kWh.

Due to the very high shipping and installation costs for a remote location, projects such as this are typically not economically feasible if self-funded. On the other hand, if grant-funded, these projects can save the community an estimated $76,051 over a period of 20 years. Fuel prices increasing by more than 25%, or subsidized electricity prices decreasing by more than 25%, make the GSHP a more viable option economically. Unsubsidized electricity prices increasing by 25% or more make a solar PV system with battery storage nearly economically viable after a 20-year period for commercial or school buildings that are not eligible for Alaska's Power Cost Equalization program.

1 Statement of Objective: Economics, Efficiency, Improvements

A new tribal building was built in the remote community of Ruby, Alaska, in the mid-2010s. After it was occupied, the City of Ruby, in collaboration with the tribe, embarked on project to retrofit the new building with a solar photovoltaic (PV) system and a ground source heat pump (GSHP) system. The solar PV component was installed in 2019, and the GSHP was installed in 2020. Both systems underwent recommissioning in 2021. Separately, the GSHP system was fitted with heat and current sensors. The data analysis detailed in this report stems from this separate project to evaluate the effectiveness and economics of the system. The data for this report were collected over the 2021–2022 winter. This paper:

- Evaluates the efficiency of a GSHP to supplement a diesel boiler for heating.
- Analyzes the solar PV to determine if the building is reaching net zero.
- Determines the economic feasibility of the full system.

2 General Overview of Systems and Location

Ruby, Alaska, is located in interior Alaska on the Yukon River, about 575 river miles upstream from the mouth of the Yukon River, or 300 air miles west of Fairbanks (see Figure 1). According to the latest U.S. Census Bureau data (U.S. Census Bureau n.d.), 139 people (primarily Alaska Native) live in Ruby. Ruby is not on a road system and is only accessible by boat, air, or snow machine. It is at almost 65° N latitude, in the sub-Arctic. The Yukon River at Ruby is 175 ft (53 m) above sea level (U.S. Geological Survey n.d.), and the airport resides on a hillside at 658 ft (200 m) above sea level (AirNav.com n.d.). The tribal building is near the river at approximately 230 ft (70 m) elevation.

Ruby is in climate zone 8 of the International Energy Conservation Code (U.S. Department of Energy 2012), and experiences approximately 14,000 heating degree days annually, based on the Alaska Climate Research Center's data for nearby Galena, Alaska (Alaska Climate Research Center n.d.). This climate zone corresponds approximately to the ecological "boreal" zone based on temperature scale—cold winters, short summers, and average mean temperature <0°C (<32°F). As such, the boreal zone represents about one-sixth of the world landmass (Sayre 2020).

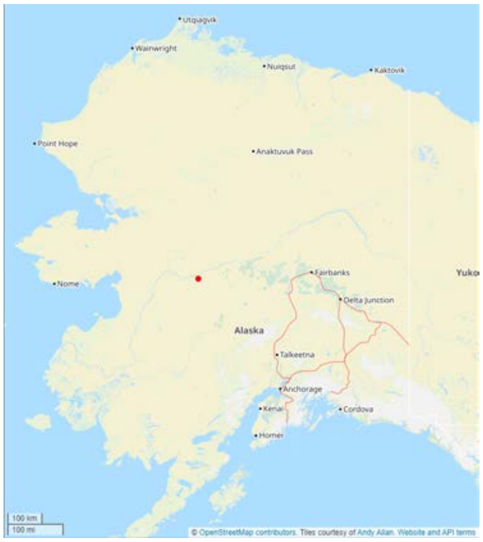

Figure 1. Map showing location of the town of Ruby, Alaska

Map from OpenStreetMap

A new tribal building in Ruby was constructed during 2016 and 2017, and the tribal administration took occupancy in fall 2017. The building is used as office space, with a kitchen attached to provide meals for Elders. In the 2019 and 2020 building seasons, as part of the U.S. Department of Energy's (DOE) "Remote Alaska Communities Energy Efficiency Competition" (RACEE), a solar PV system was installed at the tribal building together with a battery storage system large enough to carry the electrical load of the building during the three to four months of the year with the largest solar input. Some issues remained unresolved, and the system became operational after a recommissioning in the fall of 2021.

The solar PV system was smaller than originally proposed due to the limitations of the local microgrid and the solar PV panels installed during the previous two years at the clinic and city office. After checking with the funders, the unused funds from the decreased size of the solar PV installation were used to install a GSHP to supplement building heat and domestic hot water. The heat pump installation commenced with drilling the vertical loops in 2019. The rest of the installation, including the addition of the piping in the mechanical room, occurred during the summer of 2020. Both the solar PV and heat pump underwent recommissioning in the fall of 2021. At about the same time, a temporary data system was installed, which contributed the data that were analyzed for this report. The data system was removed after approximately one year. These major milestones are outlined in Figure 2.

This report documents the properties, efficiencies, costs, and challenges associated with the combined solar PV and GSHP system in a location roughly representative of one-sixth of the world's landmass.

2.1 Logistical Challenges

All of the costs outlined in this report are significantly higher than those that would be incurred in the contiguous United States on the road system. Additionally, the installation timelines are spread over longer periods. One reason is that the community of approximately 140 people does not have contractors that specialize in the installation, operation, and maintenance of the equipment installed. The procurement and installation of the systems required equipment, tools, and personnel to be transported to the site by air or barge. Commercial transportation to Ruby is available via a small, 10-seat commuter airplane from the local hub of Fairbanks, intermittent cargo flights, and barge transport in the summer months during ice-free periods. Barge transportation over the approximately 275 river miles from the on-road community of Nenana to Ruby can happen from mid-to-late May to late September, as dictated by ice-free conditions on the rivers. Equipment and machinery needed for installation thus face a short time frame for transportation to and from the community, especially when considering the time it takes to complete the installation, the timing of the return trip on a barge, and the fact that any drilling machinery is taken out of the rental market for considerably longer than the time it takes to drill.

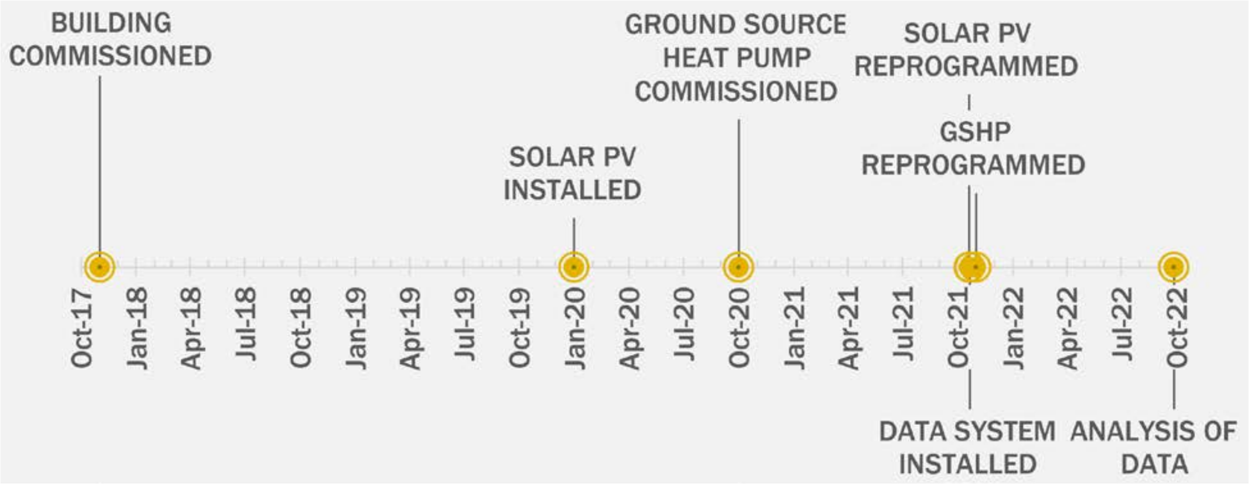

Figure 2. Relevant milestones for the solar PV and GSHP systems

3 Solar and Mechanical Installation Details

3.1 Solar Photovoltaic and Battery Setup

The solar PV system installed flat-mounted on the Ruby tribal building roof is a 10.8-kW system, meaning that under the standard testing conditions of 25°C and illuminated by 1,000 W/m^2, it would produce 10.8 kW of electricity. The National Renewable Energy Laboratory's (NREL) online solar calculator, PVWatts® (available at pvwatts.nrel.gov), estimates the system will deliver 9,000 kWh a year in Ruby, Alaska. PVWatts also does not take into account that snow falls on and covers the panels in wintertime, so it overestimates the solar power produced in winter, and it underestimates the production after the panes melt and snow is still on the ground, when reflection of light from the ground yields additional power produced.

The installation includes 32 LongiSolar panels (model LR6-72HV-340M) connected via a SolarEdge StorEdge smart inverter (model P370) to two LG Chem RESU10H type-R batteries. It also includes the local community power grid. Table 1 and Figure 3 list the components of the solar PV system.

The solar panels are mounted flat on the tribal building roof, which has a 4:12 pitch (18.4 degrees) and is oriented due south. After the snow falls, typically by mid-October, the panels are buried in snow and no power is produced until the snow melts in mid-April.

The solar output is routed to a SolarEdge system consisting of a StorEdge inverter with battery communications. This inverter can send power to the building or to charge the batteries, or it can export any remaining power to the grid. The batteries can also be charged from the grid.

Table 1. Solar PV and Battery System for the 10.8-kWh System

Application	Manufacturer	Series	Size
Solar panels (x 32)	LongiSolar	LR6-72HV-340M	340 W x 16 x 2 strings
Smart inverter	SolarEdge	SE7600A-USS2	500V AC / 240V DC
Battery x 2	LG Chem	RESU 10H	9.8 kWh capacity each
Auto-transformer	SolarEdge		

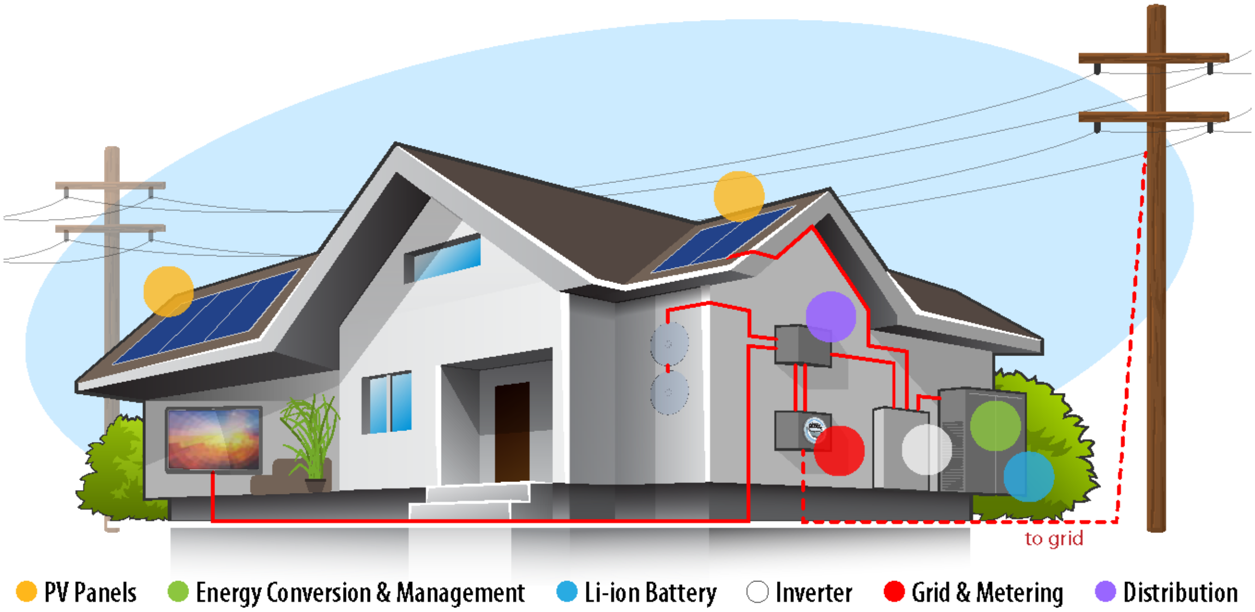

Figure 3. Solar system schematic

The PV system sends any generated power to a smart inverter, which can send the power for use in the building, or charge the battery, or send any leftover power to the grid. The battery can provide power to the building during the night. *Illustration by Alfred Hicks, NREL 66305*

The SolarEdge system includes several current transformers that measure the currents and determine the amount of power produced and consumed. The system in Ruby communicates via the internet with SolarEdge's cloud-based monitoring platform, which allows remote dashboard analysis of the current status of the system, including the electricity produced by the panels or by the batteries, electricity consumed by the building, and electricity imported from or exported to the local power grid. The system was approximately sized to provide most of the electricity for the building during three to four months of the year with the highest solar potential. Any power produced by the tribal building and not used internally is fed into the local community microgrid.

The local microgrid is run by the town of Ruby and serves the approximately 140 residents as well as commercial and community buildings. It typically generates around 500,000 kWh per year (State of Alaska n.d.). One lesson learned from this project is that the type of electric meter installed on the building is important. Some meters measure only import, some measure the absolute value of the electricity passing them, and some are bidirectional, allowing the numbers to run backward if a building is exporting solar power. In Ruby, the tribal building has a meter that measures the absolute value of the electricity passing it.

The solar PV and battery system was installed over the summer of 2019 through winter 2020 and was not operating properly until October 2021 when it was recommissioned.

3.2 Ground Source Heat Pump

The GSHP installed in Ruby was manufactured by Enertech. It is model number WS036, indicating 36 kBtu/h capacity, or 36,000 British thermal units per hour (in the product manual written as 36 MBtu/h, with the M standing for 1,000). The COP listed on the engineering drawings for the Ruby system is 2.5, and electricity usage is 2.8 kW (which are the manufacturer's specifications for this unit with −3.9°C (25°F) entering ground loop fluid temperature).

The loops in the ground are oriented vertically. There are six vertical wells about 100 feet deep to the east of the building. Based on the engineering drawings, the fluid in the ground loops is water with 20% methanol and is moving at 9 gallons per minute. The design was based on an estimated ground temperature of 25°F.

3.3 Mechanical System

Figure 4 shows a simplified schematic of the building's heating and domestic hot water system, only showing the critical components to help describe the system operation. Other components such as expansion tanks, valves, pressure and temperature gauges, air separators, air vents, bibbs, and strainers are shown in a detailed engineering drawing in Appendix A.

In a simplified version, the GSHP uses electricity to run a refrigeration cycle to transfer heat available in the fluid from its ground loops, at 25°F to 30°F (−3.9°C to −1.1°C), to the fluid moving within the building, heating it to ~110°F (43.3°C). The fluid leaving the heat pump first heats a buffer tank. The buffer tank in turn heats the building through baseboard distribution. The heat pump also heats the domestic hot water for the bathroom and kitchen.

The heat pump uses a low amount of electricity, approximately 5 W, to operate its control system. If there is a call for the heat pump to operate through the mechanical room control system, the heat pump operates to try to meet the heating need of the buffer tank. This fully operational phase of the heat pump draws significantly more electricity—the rated 2.8 kW.

The control system in the mechanical room, a Tekmar 406 model, monitors the temperatures at the sensor locations indicated in Figure 4 (sensors S1 through S5 in purple boxes in the schematic) and turns the various components on and off, such as the heat pump, the boiler, and various pumps, per its programming.

For this study, temporary temperature measurements were taken at all points denoted by red letters in Figure 4 to study the operational characteristics of the heat pump system integrated with the existing hydronic heating system of the building, as outlined in Section 5.2. The heat pump desuperheater loop and the glycol makeup package each have internal pumps supplying the necessary pressure to drive the fluid through their respective fluid lines.

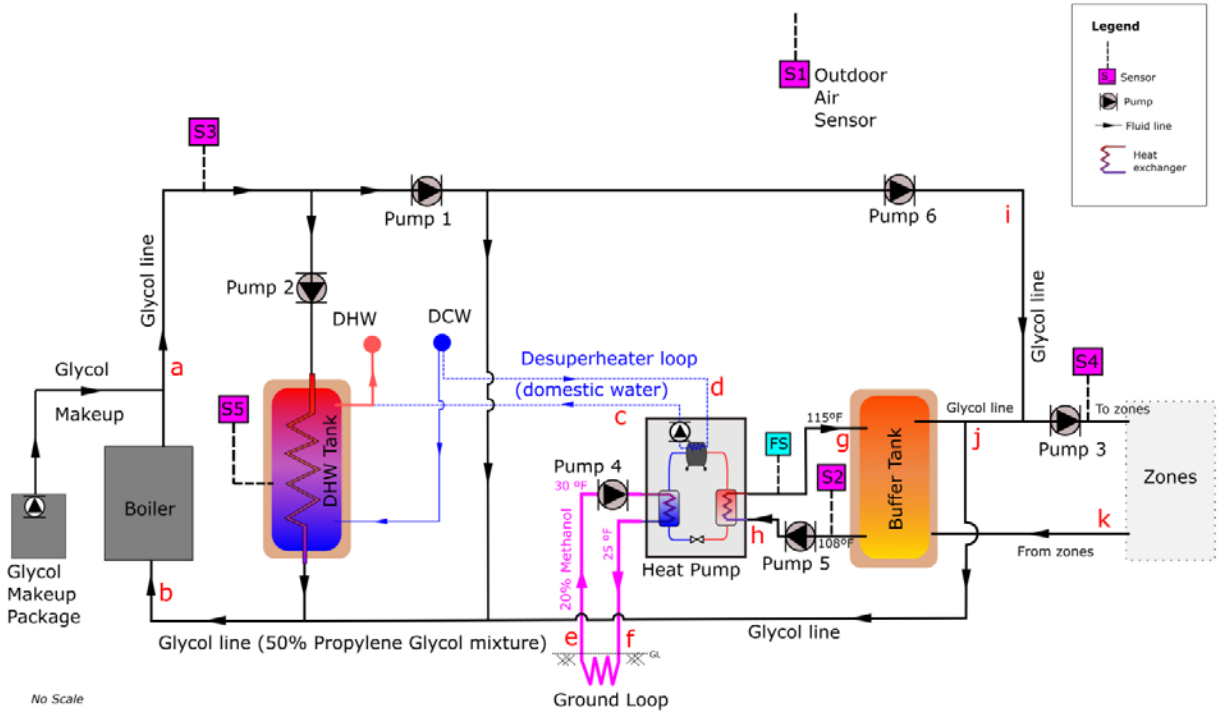

Figure 4. Schematic drawing of the GSHP system installation

The letters a through k indicate locations of temperature measurements as outlined in Section 5.2. Temperature details are from the original engineering drawings.

The building heating system was designed to heat the buffer tank up to a set point determined by the outdoor temperature (measured by sensor S1 in Figure 4). Figure 5 shows the set point temperature for the tank at different outdoor temperatures. During winter months, the buffer tank is typically in the 120°F to 140°F (50°C to 60°C) range. In summer, the buffer tank temperature may be as low as 100°F (37.8°C). The buffer tank is first heated by the heat pump. If the tank doesn't reach the set point after 30 minutes, the boiler will start supplying heat to the building to supplement the heat pump. The maximum output temperature of the heat pump is 115°F (46.1°C); thus, the boiler needs to boost the delivery fluid temperature when the outdoor temperature drops below 25°F (−3.9°C).

The heat pump also supplies heat to the domestic hot water tank via a desuperheater loop. The desuperheater loop extracts heat from the heat pump compressor only when the heat pump is operating in building heating mode. At all other times, only the boiler supplies heat to the domestic hot water tank. The maximum temperature from the desuperheater supply that feeds into the domestic hot water supply line is about 125°F (51.7°C).

The GSHP was commissioned in the fall of 2020.

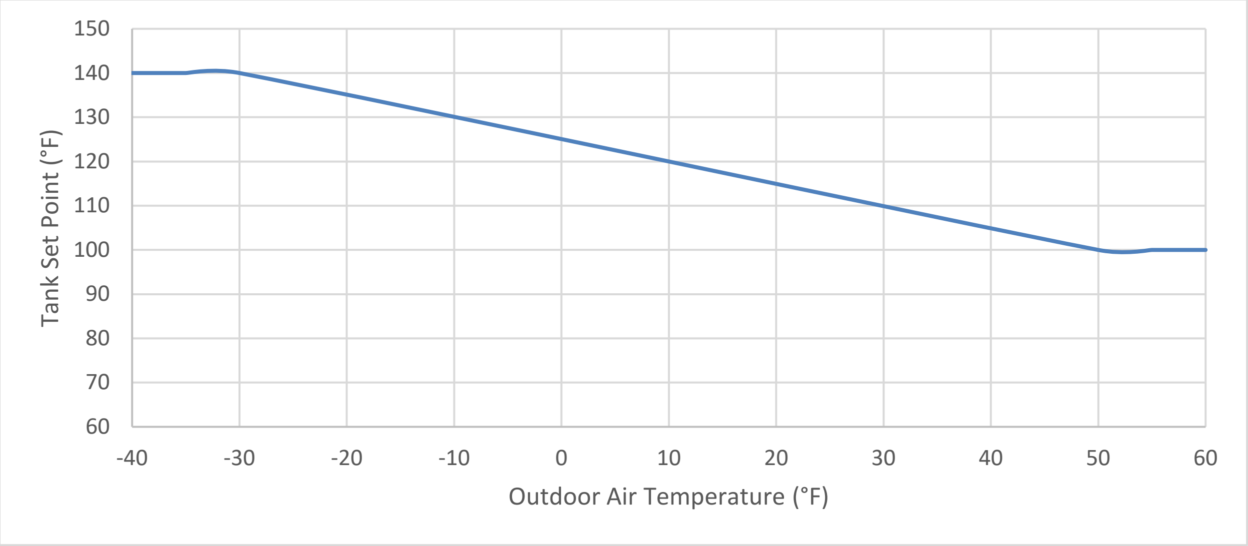

Figure 5. The outdoor set point curve for the heating element in the buffer tank

4 Cost of Installations

4.1 Installation of Ground Source Heat Pump

The town of Ruby contracted a heat pump installation company to drill and install a 3-ton vertical ground loop system. The installation costs included a new 3-ton hydronic heat pump, plumbing and pipe connections between heat distribution system and buffer tank, and the fluid in the heat pump loops and commissioning. The total cost of the installation was $77,960.

4.2 Installation of Solar PV and Battery

The town of Ruby contracted a turnkey solar company that advised, procured, and installed an off-grid solar PV and battery storage system, the SolarEdge StorEdge system. The full payment was $48,257 for a 10.8-kW solar system with a 5-kW grid-tie; another payment of $29,803 was made for a dual 9.8-kWh lithium-ion battery.

5 Data Used in Analysis

The data analysis outlined in the next section uses native data from the solar PV system, data acquired by a Campbell datalogger system temporarily deployed on the mechanical system, and weather data copied from publicly available aviation data. This section describes each group of data in more detail. In addition, the town of Ruby, which operates the local microgrid, was contacted and provided the electricity amount that the tribal building was billed for monthly.

5.1 Solar Data

Solar data come from the cloud-based SolarEdge monitoring system that receives data continuously from the Ruby SolarEdge system. The system measures the variables outlined in Figure 6 and Table 2. The measurements are saved in 15-minute increments as well as in daily, weekly, monthly, and yearly totals.

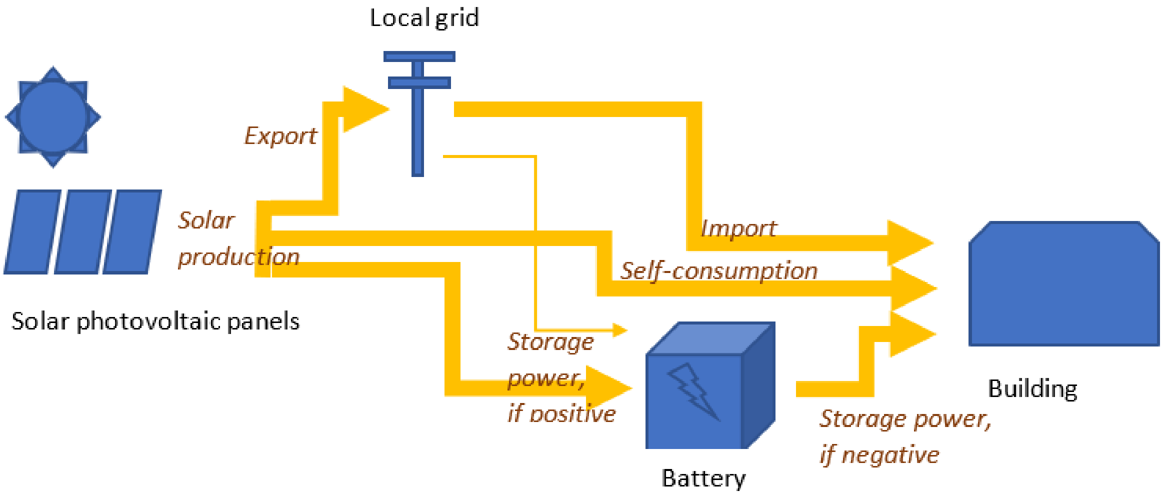

Figure 6. Schematic drawing of the solar PV system measurements

The power produced by the solar panels (solar production) is either used directly by the building (self-consumption) or stored in the battery system (storage power). Storage power shows the input into or output out of the battery system. When storage power is a negative number, it indicates battery output: the battery system is discharging to power the building. When storage power is a positive number, it indicates battery input: the battery system is getting charged by solar. On rare occasions, it is charged from the local microgrid to top off the battery to approximately 15% capacity for long-term storage needs, particularly during the six months of the year with low solar power generation.

Table 2. Variables Measured by the SolarEdge Solar PV and Battery System

Measurement[a]	Description
Solar production	All power produced by the solar panels. A sum of the power used to charge batteries (positive storage power), used by the building (self-consumption), or exported into the local electrical grid (export).
Storage power	If a positive number, the power used to charge the batteries from the solar panels, or in rare circumstances, from the grid. If a negative number, the power the batteries supplied to the building (discharge).
Self-consumption	Power supplied by the solar panels used directly by the building without being stored in the batteries.
Export	Solar power not used to charge batteries or by the building directly; exported to the local grid.
System production	Self-consumption plus export.
Import	Import of power from the local grid.
Consumption	Self-consumption of solar from PV panels plus discharge from batteries plus import from grid.

[a] All measurements are in 15-minute intervals.

5.2 Measurements From the Mechanical System

In October 2021, temperature sensors were installed on the supply and return pipes for the GSHP, the tank, and other equipment, as well as a measurement sensor for the electricity usage of the GSHP. Table 3 lists all the temperature sensors. Figure 4 and Appendix A show schematics of the sensor locations. A Campbell Scientific CR-1000X datalogger collected the data from the sensors.

Type K thermocouples measured pipe temperatures. They were deployed on the outside of the pipes within the mechanical room; all the sensors were placed on metal pipes or pipe connections. Because the sensors were on the outside the pipe, the temperatures recorded included some lag with respect to the temperatures of the fluid within the pipes. A current transformer measured the electricity usage.

Table 3. Measured Temperatures (°C) in the Mechanical Room

Measurement Location	Pipe	Location in Figure 4	Specifics[a]
GSHP	Supply	e	Temperature of fluid from ground loop
	Return	f	Temp. of fluid leaving the heat pump to the ground loop
Tank	Supply	g	Temp. of fluid from the heat pump into the tank that supplies fluid for heating the building
	Return	h	Temp. of fluid returning from the tank to the heat pump
Domestic hot water	Supply	d	Temp. of water going into domestic hot water tank from the heat pump (desuperheater loop)
	Return	c	Temp. of domestic cold water entering the heat pump (desuperheater loop)
Boiler	Supply	a	Temp. of fluid leaving the boiler
	Return	b	Temp. of fluid returning to the boiler
Building	Supply	j	Temp. of fluid supplying heating to the building
	Return	k	Temp. of fluid returning from heating the building
Boiler loop	Supply	i	Temp. of fluid being added from the boiler to the loop heating the building

[a] Measurements were in 30-second intervals as well as 1-hour averages.

The data from the mechanical system consisted of approximately 11 months of data with two discontinuities, as shown in Figure 7. Both happened when the data acquisition system was inadvertently unplugged from the power supply, and the loss of power was not noticed immediately due to the remoteness of the site.

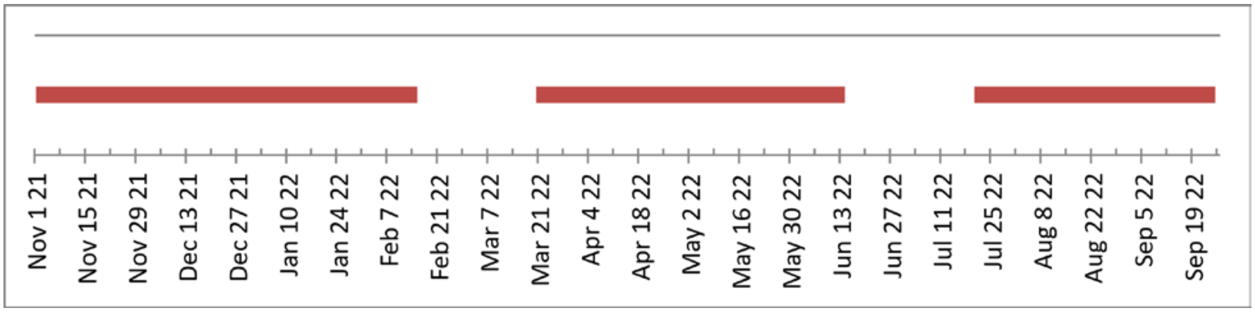

Figure 7. Collected data range, including two large discontinuities

In addition to the data discontinuities noted above, the heat pump did not run on all days. Without having access to the control system programming, it is not clear why the heat pump ran, for example, for only half the days in December.

5.3 Weather Data

Any weather data described in this report are publicly available from the Federal Aviation Administration's (FAA) Automated Weather Observation Systems meteorological terminal air report (METAR) stations located either in Ruby, Alaska (station: PARY), or about 50 miles downriver in Galena, Alaska (station: PAGA). More information about these is in Appendix B.

Where data were missing in the Ruby recordings, the value from the Galena recording from the same time was substituted for a more complete data set. For the purposes of this analysis, the data collected from the Galena weather station were combined with the data from Ruby using an inner join. Despite the stations being 40 miles distant, the weather in the ~1-km-wide Yukon River is similar, and the major differences between the two are due to altitude differences: the Galena airport is by the Yukon River, whereas the Ruby one is on top of the ridge, potentially yielding significantly warmer temperatures (20°F or more) in winter due to "inversion." The inversion often present on wind-free winter days also means that the Ruby temperatures, measured at an altitude of 200 m above sea level, may be warmer than the temperatures that the tribal building, at 70 m above sea level, experienced.

6 Analysis

6.1 Solar Production

Solar power is produced by the Ruby tribal building from approximately mid-April, when the snow melts off the rooftop-mounted panels, to approximately October. The actual production is shown in Figure 8, together with predicted production based on PVWatts. The actual solar production is at times higher or lower than the predicted production. Specifically, in midwinter, there is no production from the system due to snow cover. In late spring and early summer, production is higher than predicted, possibly due to reflection off snow cover or due to weather conditions (for example, it may be less cloudy than the predicted data used by the model). Production is lower than predicted for August and September, possibly due to weather conditions. The remaining months of the year only have predicted values, as the data were not available at the time of writing this report.

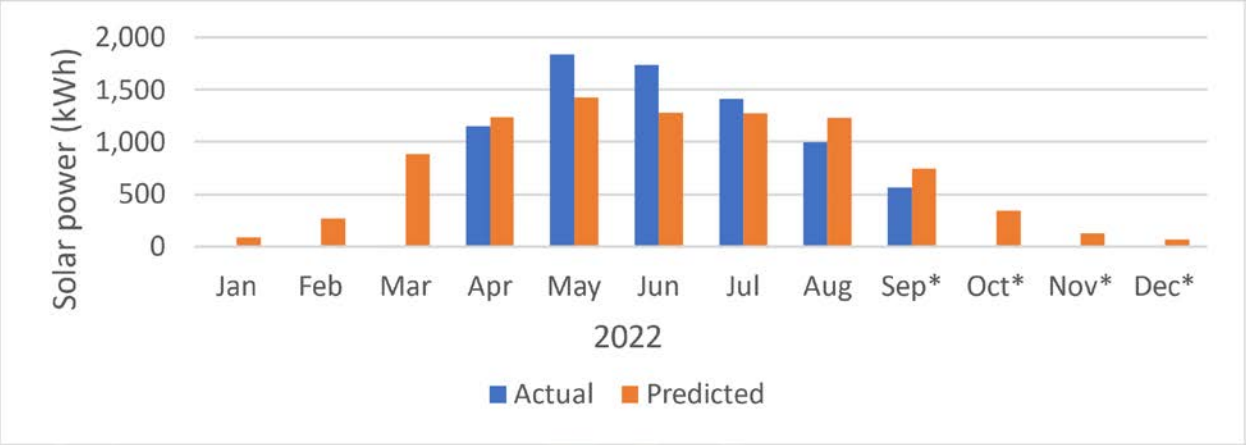

Figure 8. Actual and predicted solar production in 2022.

The total solar production of the SolarEdge system in Ruby for 2022 is shown in blue and starts when the snow melted off the panels in April 2022. The September data include the first 27 days, concluding at the time of the writing of this report. There are no data for October through December (*). The solar production predicted by PVWatts is shown in orange. There is very little solar production in Alaska in winter.

6.1.1 Sample Weekly Solar Production

Figure 9 shows an example of the solar production: one for a week very soon after the snow melted in April 2022. The week had significant solar production, indicated by the green peaks. The power consumed by the building is indicated by red if it is imported from the grid, blue if it comes directly from the solar panels, or purple (where blue and red overlap) if it comes from the batteries charged by the solar. Green shows the additional solar production, which either charges the battery or is exported. The bottom portion of each week shows the battery charge, which varies between 100% and ~15%. The system does not let the battery discharge further to ensure its capacity does not degrade.

04/15/2022 - 04/22/2022

System Production: 460.7 kWh

69% | 31%

Self-consumption: 317.49 kWh

Export: 143.22 kWh

Consumption: 397.61 kWh

80% | 20%

Self-consumption: 317.49 kWh

└ 189.39 kWh from batteries (59.7%)

Import: 80.13 kWh

From: 04/15/2022

Figure 9. Solar production in April

A screenshot from the online monitoring of one week of solar production from the solar panels and batteries. Green indicates the production from the PV panels. The consumption of the building is indicated by blue when it is the direct consumption of that power by the building, purple when the power comes from batteries, and red when the power is imported from the grid.

The week shows that the solar panels supplied enough solar for use in the building during the day and during part of the night from the battery discharge, but at the end of each night, some power had to be imported (shown in red).

6.1.2 Electricity Use for Last Three Years and Solar for Last Year

The solar power production can be compared to the electricity usage by the building. The electricity purchased from the town is shown in Figure 10 as a blue line. Some data are missing, and if only one data point was missing, it was estimated as the average of its two neighbors.

Some time periods relevant for energy usage to keep in mind include fall 2020 when the heat pump was turned on (and the significant increase in power usage thereafter); fall 2021 when the solar PV was reprogrammed to work properly (solar data only start at that point); and later fall 2021 when the control system was reprogrammed, after which the recommissioning likely impacted the usage by the heat pump, decreasing the power usage in winter 2021–2022 compared to the previous winter.

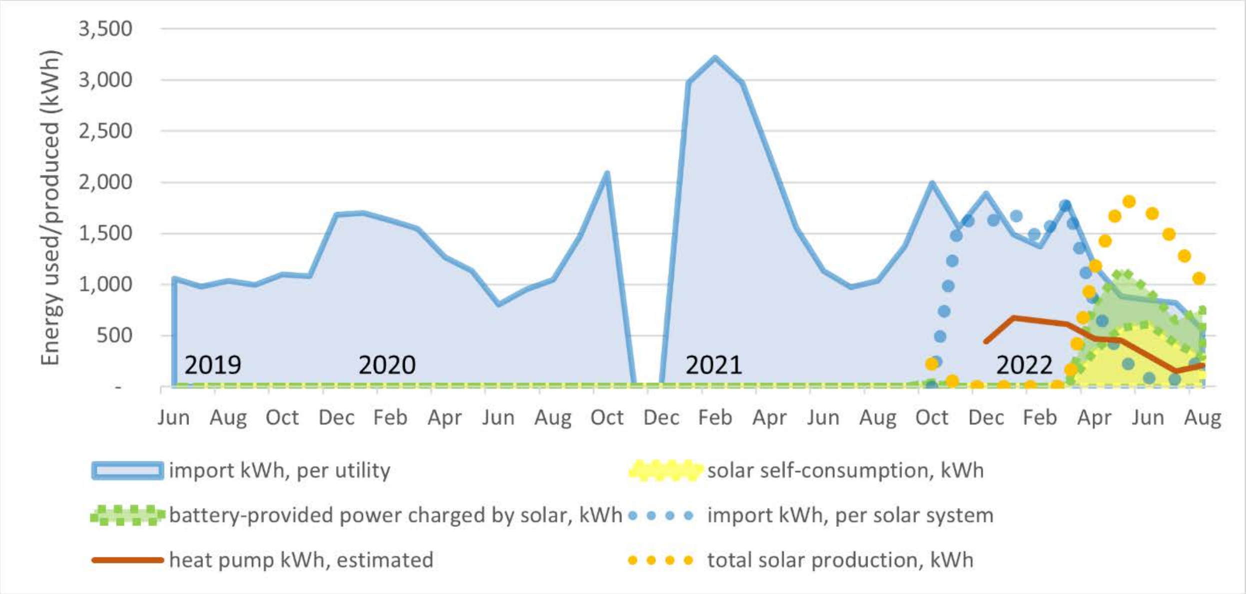

Figure 10. Electricity usage in the building over the last three years, solar production and heat pump estimated use over the last year

This graph shows the energy billed by the utility company over the last three years as a blue line. The use increased significantly after the heat pump was turned on in the fall of 2020. The data system was installed in October 2021, the solar PV system was reprogrammed at that point as well, and the control system, which directs the heat pump, was likewise reprogrammed shortly thereafter. The data system allowed us to estimate the heat pump usage, shown in brown. The solar PV system data are shown in dotted lines—energy used by the building, according to the solar, in blue dots, the solar produced overall in orange dots, solar used directly by the building in the yellow area, and solar first stored in batteries in the green area. The data for April 2021 and June 2022 for import from the utility were missing and are shown as averages of neighboring months. Note the significant billing in summer 2022 (blue line) compared to import per the solar PV system (blue dots), indicating the meter is counting the absolute value of electricity passing it, including exported electricity.

The solar panels were covered by snow within days of the system reprogram in October 2021. There was no solar electricity, shown as the yellow dotted line, produced in winter. In April the snow melted, and the solar PV system started delivering electricity to the building. The electricity consumed by the building directly is shown as a yellow area; the electricity stored first in the batteries before consumption is shown in green. During the peak of the summer, more electricity is produced than the building can consume, and that excess electricity is fed into the local microgrid.

In summer 2022, there was an interesting discrepancy between the electricity billed by the utility (blue line) and that shown as being imported by the solar system (blue dotted line) (note that the

June billing statement is not available, and that value was estimated as the average of the neighboring months). The likely culprit was identified as an electric meter that counts the electricity that passes it, no matter which direction the electricity flows. In other words, in the current setup, the building may be paying to export electricity into the microgrid at the same cost as it would pull electricity from the microgrid. A review of the meter installed by the on-site technician clarified that this is indeed the case. The issue may potentially be corrected by installing a different meter.

6.1.3 Summary of Monthly and Annual Solar Production

The monthly and estimated annual production of the solar PV system are shown in Table 4 together with estimated heat pump power usage. The billed energy from the utility by month is compared to the imported energy according to the solar PV system. The electric meter that the utility uses counts the absolute value of the electricity passing it. The billed electricity usage is based on an “undetented” meter, meaning it counts the electricity moving in either direction, and counts both import and export absolute values—the tribe at present pays to export its electricity at the same rate it pays to import it. Thus the billed 2021–2022 electricity is not indicative of the amount of electricity the building had to import, as it presently comprises the absolute value of import plus absolute value of export. In order to estimate the impact of the solar system on the building power, the billed 2019–2020 electricity, before the solar system was fully commissioned, and before there was solar export that would impact the ‘billed” amount, can be compared to the imported 2021–2022 electricity per the solar system. For 2019–2020, 15,214 kWh were used by the building, based on utility records. For 2021–2022, 12,900 kWh were used by the building per the solar system report. If the meter on the tribal building is replaced to a “detented” meter, this is the number that the tribe may expect to pay.

Table 4. Monthly and Estimated Annual Energy Usage

Date	Billed kWh by Utility	Import kWh, per Solar System	Total Solar Production[b], kWh	Total Solar Used Within Building	Solar Self-Consumption, kWh	Battery-Provided Energy Charged by Solar, kWh	Heat Pump kWh, Estimated
12/1/2021	1,893	1,605	-		-	-	442[c]
1/1/2022	1,492	1,698	-	-	-	-	673
2/1/2022	1,370	1,436	-	-	-	-	641[d]
3/1/2022	1,804	1,805	7	7	7	0	609
4/1/2022	1,186	790	1,154	806	347	459	467
5/1/2022	885	270	1,840	1,156	575	582	450
6/1/2022	852[a]	82	1,742	941	611	330	301
7/1/2022	818	74	1,413	643	420	223	152
8/1/2022	559	282	1,003	755	294	461	206
Estimated 2021–2022	**15,900**	**12,900**	**7,652**	**4,705**			**5,760**
2019–2020	**15,214**	**n/a**	**n/a**	**n/a**			**n/a**

[a] June billing data were missing and are the average of neighboring months.

[b] Total solar production includes that used within the building, which can be self-consumed directly or go through the battery storage.

[c] In December, the heat pump ran about half the time.

[d] February heat pump number is the average of the neighboring months due to data discontinuities.

On an annual basis, extrapolated from data between December 2021 and August 2022, the solar PV system is estimated to have produced approximately 7,600 kWh. This compares favorably with the estimated 5,800 kWh used by the heat pump (annually) in terms of offsetting the electricity needed. However, only 4,700 kWh of the solar power produced was used within the building, with the remaining ~2,900 kWh being exported to the microgrid. In terms of annual usage, the imported 2021–2022 electricity amount per the solar PV system is less than the billed 2019–2020 electricity amount, before either the GSHP or the solar PV was turned on.

6.2 Heat Pump Analysis

During the course of almost a year of monitoring, either the heat pump or the datalogger were off for some periods of time—for example, due to unintentional unplugging of the datalogger that was shown in Figure 7. Additionally, at times the heat pump, controlled by the control system, exhibited irregular operations, such as not turning on for a week at a time in cold weather. This is potentially due to the high return temperature from the building when the boiler is heating the baseboard fluid to 140°F. The return fluid flows directly to the buffer tank and sometimes keeps the tank above the temperature that would engage the heat pump. Without having access to the control system programming, this is not discussed further, though the behavior is taken into account when calculating the heat pump power usage.

For the power usage and the economics of the system, data for the heat pump were examined for the months of January to April. One-week intervals within each month were taken when the heat pump was operating, and the power usage was calculated for those weeks. This data set was then expanded to cover the entire month, giving estimated monthly power used by the heat pump. Note that this analysis uses the weeks when the control system calls on heat from the GSHP, and these are expanded to the entire month. At present, that is not the case, and the control system calls on the GSHP only one to two weeks per month. In effect, the analysis presumes the issue with the control system programming has been resolved and outlines the energy savings if the GSHP operated continuously.

The average winter temperatures in interior Alaska are lowest in mid-January. As such, it was estimated that the temperatures in the first half of winter, October to mid-January, are approximately the same as those for the second half, from mid-January to April. The heat pump power usage was thus estimated to be twice the sum for half of January, and all of February, March, and April.

The performance of heating or cooling devices, including heat pumps, can be quantified in terms of their COP. The COP is defined as the ratio of the energy put out by the device to the energy put into the device. For example, electric baseboards have a COP of nearly 1 since almost all the electricity used by baseboards is converted to heat, leading to a fraction of about one unit of energy output per one unit of energy input, which yields a COP of ~1.

In contrast to baseboards, heat pumps do not create heat, they move heat, and for every 1 unit of power supplied, they can move 2 or more units of heat into a building. Moving 2 units of heat for 1 unit of power would yield a COP of 2/1, or 2. In this study, COP was calculated by dividing the measured heat the heat pump delivered by the measured electricity used by the heat pump.

6.2.1 Coefficient of Performance Calculations

The Campbell Scientific CR-1000X datalogger performs calculations during the data acquisition and saves those values in tabular form that can be remotely accessed via an online research data system. These include the heat reaching the tank, based on the volumetric flow rate and temperature difference of the fluid flowing to the tank. Using these values, the COP can be calculated.

The measured temperatures at points g and h in Figure 4 provide the difference in temperature (ΔT) between the fluid leaving the heat pump for the buffer tank and the fluid returning to the heat pump. This difference in temperature between the two fluid lines indicates the change in temperature due to the heat delivered by the heat pump to the building. Multiplying this temperature difference, ΔT (°C), with the specific heat of the working fluid, c (3,588.1 J/kg·°C = 0.875 BTU/lb·°F), which in this case is 50% propylene glycol mixture, the volumetric flow rate, q_v (10 gal/min = 0.000631 m^3/s = 0.0223 ft^3/s) and the density, ρ (1,022 kg/m^3 = 63.81 lb/ft^3), of the working fluid gives the rate of heat delivered by the heat pump (in Btu/h). Dividing this heat delivery rate by the electrical power consumed by the heat pump, P (in kW, converted to Btu/h), gives the COP of the heat pump (Eq. 1):

$$COP\ (direct\ method) = \frac{volumetric\ flow\ rate \cdot density \cdot specific\ heat \cdot \Delta T}{heat\ pump_{kW}} = \frac{q_v \cdot \rho \cdot c \cdot \Delta T}{heat\ pump_{kW}} \qquad (1)$$

Note that this calculation ignores the water delivered to the desuperheater loop for domestic hot water, as this is not measured, and presumed to be minimal. As we can see from Figure 11, the heat pump COP ranges between 2 and 4, ignoring the few instantaneous spikes. The heat pump COP can also be seen to gradually increase with the season, with the lowest values during the winter season and the highest values during the summer and fall seasons, as expected. The average value of the COP (direct method) for the measurement period between November 2021 and September 2022 was found to be 2.68.

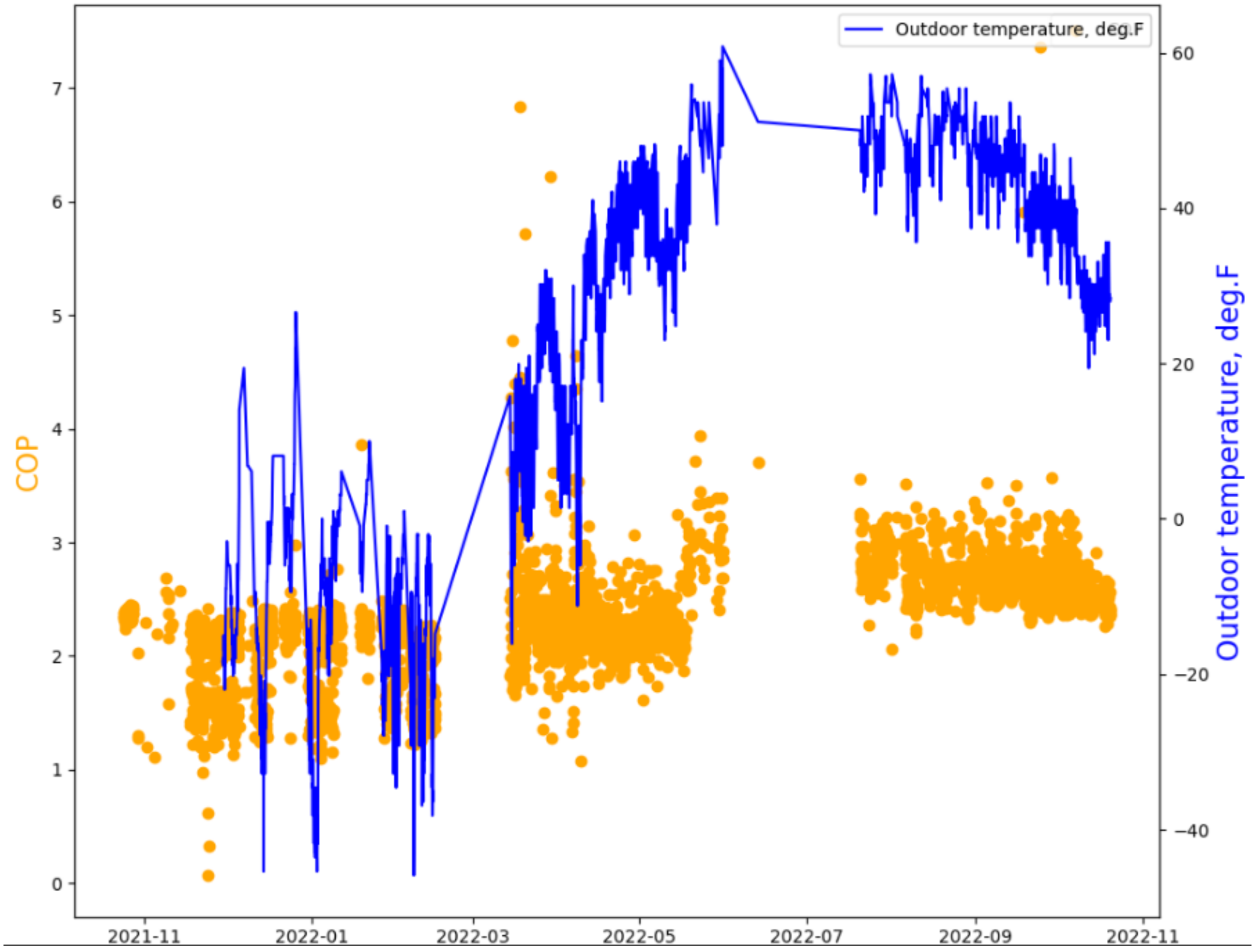

Figure 11. Direct calculation of COP and outdoor temperature as a function of time

This graph shows the COP calculated directly from the variables recorded by the data system, as well as the outdoor temperature, over the course of a year.

Alternatively, using the same data, a simpler ratio can also be computed to determine the COP via the electrical power consumed by the heat pump measured using the data from the power meter on the heat pump ($heat\ pump_{kWh}$), and the amount of heat energy supplied to the buffer tank by the heat pump ($tank_{kWh}$). If the collected data is regressed with $tank_{kWh}$ on the y-axis, and $heat\ pump_{kWh}$ on the x-axis, the COP of the heat pump is given by the slope of the regression line (Eq. 2):

$$COP\ (slope\ method) = \frac{tank_{kWh}}{heat\ pump_{kWh}} \tag{2}$$

The COP was calculated using the slope method for the data available for each month. The data are shown in Figure 12. Each month was assigned a temperature, with winter months being bluish hues, shoulder seasons yellowish, and summer reddish. The warmer hues from the summer months have a larger slope, indicating a better COP, than the bluish hues from the winter months. There are also times when the heat pump turned off, but the tank was warm—

these are the points stacked along the *y*-axis. The slope-calculated COP is 2.69, very close to that calculated above.

The COP as a function of month calculated directly is shown in Table 5, together with the heat pump and the boiler runtimes. Both the figure and the graph show that despite the wells for the GSHP being vertical, the season influences the heat pump function, and warmer months show a better performance. Warmer outside temperature requires lower delivery temperature from the heat pump, which increases the COP. The COP is also higher in the early fall, which is likely due to the slow summer warming of the soil. The soil tends to reach the greatest depth of warming in October.

Table 5 also shows that in the middle of winter, the heat pump is supplementing the boiler, and the boiler runs for a longer time than the heat pump. In February, the two run approximately equally, and in summer, the heat pump runs longer than the boiler. One issue that is also visible from Table 5 is that the heat pump behaves differently in warmer months, with more on/off cycles and also more runtime, than in winter months. Without having access to the control system programming, this issue is noted but not discussed further.

Note that for either method of calculating the COP, the data set used comes from the same source and is incomplete, as there were times when the CR-1000X datalogger was inadvertently unplugged, or when the heat pump was not operating for unknown reasons. The latter occurred more often than expected, and there were often one- to two-week periods throughout the year, including in midwinter conditions when the heat demand from the building was high, when the heat pump did not run at all. It is not known if this was due to the control system programming or for other reasons.

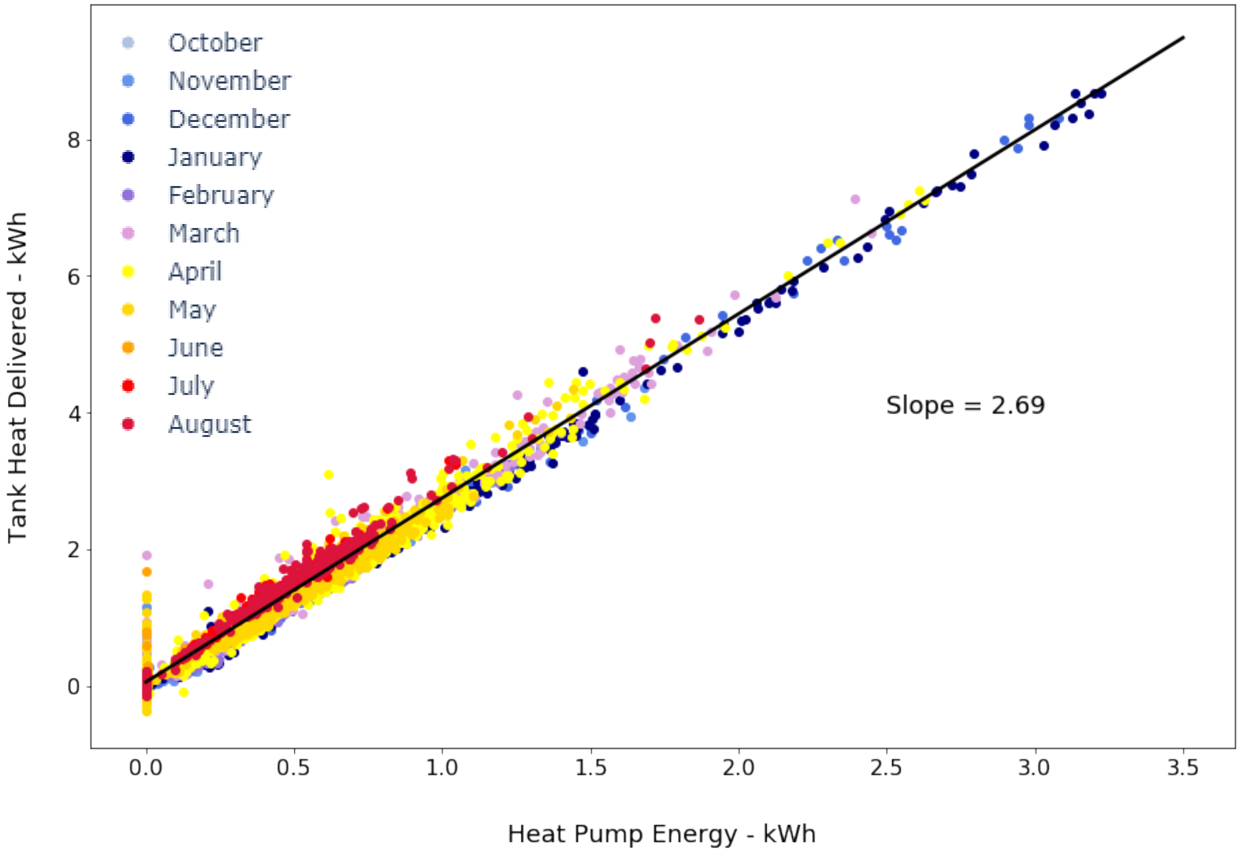

Figure 12. Calculation of COP using the slope method. The COP is the slope of the line, and the color indicates the month in which the data point occurred.

Table 5. Heat Pump COP and Runtime as a Function of Month

Month	Heat Pump On/Off Cycles	Heat Pump Total Runtime (hours)	COP	Boiler Total Runtime (hours)
November	348	43.9	2.51	96.2
December	387	72.5	2.66	118.1
January	465	104.2	2.65	140.6
February[a]	289	37.7	2.61	45.1
March[a]	305	61.9	2.70	16.1
April	757	128.9	2.72	29.0
May	534	69.4	2.64	7.0
June[a]	1	n/a	n/a	n/a
July	211	18.5	3.20	0.0
August	720	18.2	3.03	0.2

[a] The data set is incomplete and does not cover all days for all months, especially for the months footnoted.

The average annual COP across the data set calculated by the direct method is 2.68 and 2.69 via the slope method. This is better than the 2.5 value used as a basis for the design of the system, indicating the heat pump is working better than designed. In summer months, the COP reaches a value of 3 or higher. The COP in this analysis was lowest in November, at 2.51. The boiler did not run much in the warmer months, which allowed the heat pump to run without the boiler interfering with the temperature in the buffer tank.

6.2.2 Heat Pump Function and System Runtimes

The heat pump/boiler system runtimes were metered over the course of the project and tallied based on the outdoor temperature. Table 6 shows, in 10°F bins, the summed duration of outside temperatures for that temperature range, and the runtime of the heat pump or the boiler. The COP is also shown and discussed in a following section. Not shown is temperature range above 50°F, when the COP was above 3. The heat pump was not run in cooling mode. The table shows that the boiler ran a higher percentage of the time as the temperature got colder, and the heat pump also ran more as the outside temperature got colder. The two units seemed to be working in tandem to supply enough heat to the building.

When the temperature was above 30°F the boiler ran very minimally, which is expected based on the outdoor set point control curve (Figure 5). Specifically at 30°F outside temperature, the tank set point was 110°F, meaning the control system tried to keep the tank to that temperature, which the heat pump could supply. The tank set point increased as outside temperature cooled. For example, at 10°F outside temperature, the tank set point was 120°F. The heat pump could not supply fluid at that temperature, and the boiler had to turn on. Due to the set point curve, the boiler ran minimally above an outside temperature of 30°F because the GSHP could supply the temperature that the heat tank was set to. These estimates probably undercount the boiler run time slightly as boiler heating of domestic hot water was not metered.

Table 6. System Runtimes

Temperature	Total Time	Heat Pump Runtime		Heat Pump COP	Boiler Runtime	
Range	Days	Days	% of Time		Days	% of Time
40°F to 50°F	42.13	7.88	18.7%	2.56	0.09	0.2%
30°F to 40°F	32.62	10.73	32.9%	2.44	0.84	2.6%
20°F to 30°F	19.76	5.86	29.7%	2.45	0.82	4.1%
10°F to 20°F	20.9	2.17	10.4%	2.34	1.80	8.6%
0°F to 10°F	24.11	1.80	7.5%	2.33	3.45	14.3%
−10°F to 0°F	32.08	3.66	11.4%	2.32	4.20	13.1%
−20°F to −10°F	19.64	2.53	12.9%	2.33	2.22	11.3%
−30°F to −20°F	9.69	1.31	13.5%	2.37	1.33	13.7%
−40°F to −30°F	3.04	0.70	23.1%	2.35	0.52	17.2%

7 Economic Analysis

7.1 Background

The electricity for the tribal building in Ruby is subsidized by the state of Alaska Power Cost Equalization (PCE) program. The PCE program provides economic assistance to communities and residents of rural electric utilities by reducing the cost of some electricity sold to residential and community consumers. The PCE program thus reduces the electric rates paid by rural consumers to levels more comparable to bigger cities in Alaska such as Anchorage, Juneau, and Fairbanks. The program is administered by Alaska Energy Authority and serves 193 communities that are largely reliant on diesel fuel for power generation (Alaska Energy Authority n.d.). It is important to note that the PCE can only be used for residential homes or community buildings and does not apply to commercial buildings or schools. Residential customers can have a PCE credit for the first 500 kWh per month. Community facilities are capped at 70 kWh per resident per month. In this economic analysis, the purchased electricity price that is under the PCE program for Ruby is used for one scenario and is compared to a scenario without PCE, which would be applicable to, for example, commercial buildings or community buildings for years when the Alaska legislature does not fund the PCE program. The formula for the reimbursement includes a floor and ceiling value and can be read about on page 7 of the Power Cost Equalization Program Statistical Report FY 2021 (Alaska Energy Authority 2022). These do not come into play for the Ruby tribal building at present.

All cost data such as contracted price agreements and electricity bill and fuel usage were provided by Tanana Chiefs Conference, Ruby Tribal Council, and the town of Ruby. The capital costs for the solar PV systems and the GSHP were both under turnkey agreements, and thus it is difficult to price the cost of doing business in such a remote location. As the installation is for only one tribal building in a remote location, it is expected that the cost is higher than it would be in a more urban setting. As such, the documented cost of the systems was comparably higher to similar systems in the lower 48 states, with the excess cost reflected in the cost to ship and deliver in a remote setting and the higher cost of labor in Alaska.

Given the lack of data available from other rural Alaska settings, the capital cost and economic analysis is only reflective of the installation for the town of Ruby.

7.2 Methodology

Simple economic methods such as net present value (NPV), internal rate of return (IRR), and payback period (PP) were used to conduct economic feasibility studies based on electricity and fuel consumption per Table 7. A positive NPV represents a financially positive project for the period of time considered, meaning the invested money from the project yields more than the same amount would yield in a bank account with the interest rate specified in Table 8 less the initial investment. This value can be calculated both from the funder's perspective, when it includes the initial investment, and from the community's perspective, where the project is funded by a grant and there is no initial investment cost. The NPV from the community perspective is also the breakeven cost—the limit on the cost of the project in order for it to be financially viable. Internal rate of return is calculated based on the savings over the period of time considered. Payback period calculates how long it would take to pay off the investment using the yearly savings. Inflation of fuel and electricity is assumed based on the average inflation rate from the U.S. Bureau of Labor Statistics. The economic analysis is based on 20 years to accommodate the lifespan of the solar PV system installed. While solar panels can still function after 20 years, the efficiency drops thereafter, and the analysis is only for this period. The GSHP has a similar expected lifetime for the pump itself, with the underground portion expected to last 25–50 years. No salvage value is assigned to either system, as there is no method to calculate the salvage value of the heat pump or the cost or value to reasonably remove and recycle parts in rural Alaska.

Table 7. Economic Methods Used

Value	Brief Description	Formula[a]
NPV	Net present value, or net present worth. Compares the future cash flows to the initial investment. For funders, the initial investment is the cost of the project. For the community, the initial investment cost is zero, and the NPV for community also presents the breakeven cost.	$NPV = \sum_{t=1}^{N} \frac{F_t}{(1+i)^t} - I$
IRR	Internal rate of return, the interest rate when the equivalent worth of cash inflows equates to the equivalent worth of cash outflows.	$IRR = i'\% \sum_{t=0}^{N} R_t(P/F, i\%, k) = \sum_{t=0}^{N} E_t(P/F, i\%, k)$
PP	Payback period, the number of years required for cash inflows to equal the cash outflows.	$PP = \theta, where \sum_{t=1}^{\theta} (R_t - E_t) - I \geq 0$

[a] Variables: *i* = effective interest rate; *t* = index for each study period; *F* = future cash flow at the end of period *t*; *N* = number of study periods; *I* = initial investment; R_t = net revenue or savings for the *t*th year; E_t = net expenditure for the *t*th year; *i*%= internal rate of return.

The parameters used for economic analysis are displayed in Table 8. The annual consumption for heating fuel was recorded by the purchases and measurements of fuel remaining in the tank after the heating season by the maintenance technician in the building where the fuel was consumed. The price of fuel was collected from the Alaska Fuel Price report. This was then compared to the heat produced from the GSHP to verify that the heat produced was comparable to the heat that would have been produced by the boiler from the saved heating fuel.

The annual electricity use of the building was based on the information from the solar metering system. The figure agreed in general with the billed electricity to the town of Ruby when both the import and export was taken into account (as previously discussed, it appears that the meter installed by the town counts the absolute value of kilowatt passing through, whether importing from the grid or exporting to the grid). Since the average lowest winter temperature is in mid-January, the electricity consumption for the GSHP system was calculated from the runtime for the heat pump from mid-January to April and then doubled to reflect the annual consumption. The annual electricity produced from the solar PV system only considers electricity that was fed into the battery and tribal building and not to Ruby's microgrid, as there is no financial compensation for that energy and it does not include decreasing output due to soiling of the panels.

Table 8. Variables Used in Economic Analysis

Item	Value	Unit
Solar PV and battery system total cost	78,060	$
GSHP system total cost	77,960	$
Annual heating fuel before heat pump	1,070	gal
Annual heating fuel after heat pump	566	gal
Annual heating fuel used with heat pump	535	gal
Annual electricity use (building)	12,900	kWh
Annual electricity use (heat pump)	5,793	kWh
Annual solar production used within building	4,705	kWh
Annual heating from heat pump	59,785,064	Btu
Electricity price	0.54	$/kWh
Electricity price with PCE	0.2003	$/kWh
Electricity inflation	1.57	%
PCE refund	−0.3397	$/kWh
Fuel price	5.50	$/gal
Fuel inflation	3.80	%
Interest rate	0.3	%

In this section, the economic feasibility for a scenario where only the solar PV and battery system was installed was compared against a scenario with only the GSHP system and a scenario with both combined. For all scenarios, the perspective from DOE and the RACEE program and the perspective from the community were taken into account. The analysis was then repeated without the PCE adjustment. Most of the limitations of this economic analysis stems from the lack of continuous data and lack of price transparency for the installed systems. Furthermore, factors such as environmental awareness, energy security, and resiliency are not addressed in the simple economic analysis; however, resiliency is addressed later in the results.

7.3 Results

7.3.1 Economic Feasibility for Current Conditions

For the case of subsidized electricity costs due to PCE and a 20-year time period, Table 9 compares the cost of the systems to the net present value, internal rate of return, and payback period from the funder's perspective, and the net present value, or breakeven cost, for the community, which is the maximum cost of the system that would make the community come out even after 20 years. The table shows that for the 20-year lifespan considered in this analysis, all of the scenarios—whether the solar system only, GSHP only, or combined—cost more money than would be recovered by the savings realized: the net present value is negative. On the other hand, if these systems are gifted to the community (i.e., cost is $0), the community realizes savings in the tens of thousands of dollars range, as shown by the last column in this table. This column, the net present value of savings to the community, is effectively also the breakeven cost—the upper limit of the cost of each system that would result in an economically viable system. For example, for buildings that can tap into the energy subsidy (with PCE), the solar PV system would need to cost at most $21,567 in order to realize savings over the 20-year estimated lifespan of the system.

Table 9. Results for the Different Economic Methods With PCE, 20-Year Scenario

Scenarios (20 Years)	Cost	NPV ($) Funders	IRR (%)	Payback Period (years)	NPV ($) of Savings to Community = Breakeven Cost
Solar and Battery Only	$78,060	($56,324)	−9.5%	53	$21,567
GSHP Only	$77,960	($23,405)	−2.5%	25	$54,485
Solar and GSHP	$156,020	($79,729)	−5.3%	31	$76,052

For the scenario where the PCE is in place, the solar PV and battery system shows the lowest internal rate of return at −9.5%, negative net present value of $56,324, and a payback period of 53 years. This shows that the PCE covers many of the community's electricity costs and introducing the solar PV system does not provide the highest gain for the community. The GSHP-only scenario, from the funder's perspective, shows the highest internal rate of return at

−2.5%, with a negative NPV of $23,405 and payback period of 25 years. Installing both systems would have the lowest NPV at a negative $79,729 for the funders. This indicates that from the funder's point of view, utilizing the state's PCE savings would benefit the GSHP system the most. Over the expected life of the solar panels, doing nothing would cost the tribe $240k in utilities for the building.

As the systems installed were provided to the community from a grant, it can be considered a zero-cost installation from the community's perspective, and the cost-benefit analysis for the system will only take into consideration the positive cash flow as savings that can be achieved for the community as a whole. For the solar PV and battery system only, the savings that are generated for the community results in $21,567 for the 20-year duration. For the GSHP system only, the savings that are generated amount to $54,484. Installing both the solar PV with battery system and the GSHP system results in savings of $76,051 for the community.

7.3.2 Economic Feasibility Without Power Cost Equalization

For the case of unsubsidized electricity values that commercial buildings and schools pay, and a 20-year time period, Table 10 compares the cost of the systems to the net present value, internal rate of return, and payback period from the funder's perspective, and the net present value for the community, which is also the breakeven cost, or the maximum cost of the system that would make the community come out even after 20 years. For the scenario where there is no PCE, the solar PV and battery system after 20 years shows the highest internal rate of return at −2.3%, negative net present value of $19,857, and a payback period of 25 years. This completely different conclusion emphasizes that without the PCE, the solar PV and battery system offers the most gain for the community from the funder's perspective. The finding also shows that if other community buildings have more need for the PCE allocation, than it is advisable to transfer the PCE allocation for the most benefit to the community. Similarly, for commercial buildings that do not have PCE allocations, the analysis shows that the solar panels have a payback period of 25 years and can be considered as an alternative energy source. In contrast, GSHPs, which run on electricity, would need to be very inexpensive (costing the breakeven cost of $9,449 or less) in order to make financial sense for a building that does not have subsidies for electricity, such as a commercial building or a school.

Table 10. Results for the Different Economic Methods Without PCE, 20-Year Scenario

Scenarios (20 Years)	Cost	NPV ($) Funders	IRR (%)	Payback Period (years)	NPV ($) of Savings to Community = Breakeven Cost
Solar and Battery Only	$78,060	($19,857)	−2.3%	25	$58,144
GSHP Only	$77,960	($68,306)	−11.4%	39	$9,449
Solar and GSHP	$156,020	($88,163)	−6.1%	33	$67,593

Without the assistance from the PCE program, the GSHP-only scenario provides a savings of $9,449 for the community, and from the funder's perspective it shows the lowest internal rate of return at −11.4%, with a negative NPV of $68,306, and a payback period of 39 years. This indicates that without the PCE, the electricity consumed to run the heat pump does not cover the savings realized from reduced fuel use.

Combining both systems would result in a negative NPV of $88,163 from the funder's perspective and a savings of $67,593 for the community. Interestingly, both with and without PCE, the scenario with the solar and GSHP systems combined offers little difference in the NPV, IRR, or PP, suggesting that introducing both increases the resilience in the system from policies that may influence PCE existence or value.

It must be noted that while the annual electricity consumption from the building provided by the solar panels was only 4,705 kWh, the annual electricity produced from the same system overall is estimated at 7,652 kWh, which would have offset the annual electricity consumption for the GSHP. The excess of produced electricity was sent back to the town's microgrid and was not used for the building.

7.3.3 Sensitivity Analysis

To analyze the effects that prices and inflation rates for both fuel and electricity as well as the interest rate have on the NPV of the systems installed, a sensitivity analysis was completed for all six scenarios with percentage changes for 5%, 10%, and 25% in input against the NPV output. The input variables were limited to the price of fuel, price of electricity, fuel and electricity inflation rate, and the interest rate, and a one-at-a-time method was used to compute the results. The limitations for this sensitivity analysis are due to using historical data as a baseline for the inputs, as well as ignoring the fact that increasing fuel prices drive up electricity prices in areas that depend on a diesel power plant, such as Ruby. The results of the sensitivity analysis are shown in Table 11. The variable that changes is specified by the section names in the table. In each section, the first three lines are with the electric cost subsidy (with PCE), and the next three are without the electric cost subsidy.

Table 11. Sensitivity Analysis for Net Present Value

Scenarios	−25%	−10%	−5%	0%	5%	10%	25%
NPV sensitivity analysis for fuel price, % changes from existing $5.50/gallon							
Solar and battery only	0%	0%	0%	0%	0%	0%	0%
GSHP only	−86%	−35%	−17%	0%	17%	35%	86%
Solar and GSHP	−25%	−10%	−5%	0%	5%	10%	25%
Solar and battery only, no PCE	0%	0%	0%	0%	0%	0%	0%
GSHP only, no PCE	−30%	−12%	−6%	0%	6%	12%	30%
Solar and GSHP, no PCE	−23%	−9%	−5%	0%	5%	9%	23%
NPV sensitivity analysis for electricity price, % changes from existing $0.54/kWh (or $0.2003/kWh with PCE)							
Solar and battery only	−26%	−10%	−5%	0%	5%	10%	26%
GSHP only	76%	30%	15%	0%	−15%	−30%	−76%
Solar and GSHP	4%	2%	1%	0%	−1%	−2%	−4%
Solar and battery only, no PCE	−73%	−29%	−15%	0%	15%	29%	73%
GSHP only, no PCE	26%	10%	5%	0%	−5%	−10%	−26%
Solar and GSHP, no PCE	4%	2%	1%	0%	−1%	−2%	−4%
NPV sensitivity analysis for fuel inflation rate							
Solar and battery only	0%	0%	0%	0%	0%	0%	0%
GSHP only	−35%	−14%	−7%	0%	7%	15%	39%
Solar and GSHP	−10%	−4%	−2%	0%	2%	4%	11%
Solar and battery only, no PCE	0%	0%	0%	0%	0%	0%	0%
GSHP only, no PCE	−12%	−5%	−2%	0%	3%	5%	13%
Solar and GSHP, no PCE	−9%	−4%	−2%	0%	2%	4%	10%
NPV sensitivity analysis for electricity inflation rate							
Solar and battery only	−2%	−1%	0%	0%	0%	1%	2%
GSHP only	5%	2%	1%	0%	−1%	−2%	−5%
Solar and GSHP	0%	0%	0%	0%	0%	0%	0%
Solar and battery only, no PCE	−12%	−5%	−2%	0%	2%	5%	13%
GSHP only, no PCE	4%	2%	1%	0%	−1%	−2%	−5%
Solar and GSHP, no PCE	1%	0%	0%	0%	0%	0%	−1%
NPV sensitivity analysis for interest rate							
Solar and battery only	0%	0%	0%	0%	0%	0%	0%
GSHP only	2%	1%	0%	0%	0%	−1%	−2%
Solar and GSHP	1%	0%	0%	0%	0%	0%	−1%
Solar and battery only, no PCE	2%	1%	0%	0%	0%	−1%	−2%
GSHP only, no PCE	0%	0%	0%	0%	0%	0%	0%
Solar and GSHP, no PCE	1%	0%	0%	0%	0%	0%	−1%

From the sensitivity analysis for fuel price, it can be seen that for the GSHP-only scenario, an increase or decrease in fuel prices by 5%,10%, and 25% results in a change of the NPV by 17%, 35%, and 86%, respectively, which is equivalent to a 3.45x change in output. In context, for example, if fuel prices increased by 5%, then the NPV increases by 17% from a negative NPV \$23,404 to a negative NPV of \$19,856. For a GSHP system without PCE, the sensitivity is reduced to only 1.18x, similar to a solar PV system only and a combination solar PV and GSHP system.

For the electricity price, the sensitivity analysis indicates that the GSHP system is inversely affected by the electric price change, by a factor of 3.05x. An increase in electricity price by 5% reduces the NPV by 15% and vice versa. A GSHP uses electricity, hence the inverse relationship. For the solar PV system without PCE, there is 2.92x change in output from changes in the electricity price. Unlike a heat pump, a solar PV system creates electricity, and the relationship is regular, not inverse like for a heat pump.

For both electricity inflation rate and interest rate, the sensitivity analysis shows that it has minimal effects for all systems.

In no scenario, even within the highest bands considered, ±25% change, did a system achieve a positive NPV after 20 years. The closest cases were the GSHP for fuel price increasing by 25% (NPV -\$3,206), the GSHP for electricity decreasing by 25% (NPV -\$5,561), and solar PV system for unsubsidized electricity (no PCE) increasing in cost 25% (NPV -\$5,364). All other scenarios resulted in larger negative NPV values, below -\$10,000.

One interesting item to note is that while the GSHP is the most economically attractive in terms of NPV for the current conditions, a GSHP system on its own is the most sensitive to fuel and electricity price as well as fuel inflation rates. However, for all different sensitivity percentages, installing both solar and GSHP systems reduces the sensitivity for both price and inflation rate increase and decrease. It is worth bearing in mind that even with the large ±25% span, the sensitivity analysis showed that none of the scenarios resulted in a positive NPV over a 20-year analysis.

Another item to keep in mind is that portions of the system(s), such as the underground portion of the GSHP, have an expected lifetime of 25–50 years, potentially significantly longer than the period used in this economic analysis. Even if the above-ground pump portion has to be replaced after 20 years, the system may well be economically viable if considered over a 40-year period.

7.4 Economic Conclusion

The major problems faced by many communities in rural Alaska are the high cost of energy and energy security. The introduction of renewable energy such as the solar PV with battery system and the GSHP, while not traditionally economically feasible, can provide energy resilience and security for the community. It also reduces the community's dependance on the state's program such as the PCE electric cost subsidy for residential and community buildings that can be removed or reduced based on the state's funding and policies.

Under current conditions, the GSHP installed is the most economically attractive scenario with a payback period of 25 years and −2.5% internal rate of return. However, if the electric cost subsidy was removed, or for commercial or school buildings in the community that do not receive the subsidy, the solar PV system would be the most economically attractive with a 25-year payback period and −2.3% internal rate of return. For both scenarios, installing the combined solar PV and GSHP system nets the most gain for the community at a NPV in savings of $76,051 and $67,592 with or without the PCE, respectively. Additional savings may be realized if the controls are adjusted to turn the heat pump on more consistently.

A sensitivity analysis performed concluded that installing a combined solar PV and GSHP system reduces risk from increases in fuel and electricity price as well as changes in inflation and interest rates, though none resulted in a positive net present value (a positive financial outcome) for the 20-year period considered.

8 Conclusion

Analysis of costs and power, both produced and consumed, for a solar PV storage system and a GSHP in a remote location with high heating load, over the course of approximately one year, indicated the following for this remote location with high installation, power, and fuel costs:

- The COP for the GSHP, located in building climate zone 8 or ecological "boreal" zone representing approximately one-sixth of the world's surface, is approximately 2.7 for all months. In winter the COP is low, at 2.5 or below, whereas in summer months the COP is at or above 3.0. This calculation is likely an underrepresentation of the COP, as it does not include the heat produced for domestic hot water, and the suboptimal controls likely degraded performance.

- On an annual basis, the solar PV system installed on the building produces more energy than the GSHP uses, despite being covered by snow for approximately half the year. This production includes export of extra power in the summer months once the battery of the solar PV system becomes fully charged. As such, the installation of solar PV and heat pump is almost net-zero on an annual basis. The building itself has other loads and is not net-zero. For best economic outcomes, any installation should ensure that a bidirectional meter is installed facing the grid.

- There were issues with the programming of both the solar and the heat pump systems that were not caught as the systems came online initially. While some issues have been fixed, others remain unresolved. This includes the programming of the control system in the mechanical room, which controls when the heat pump turns on and off. The heat pump turns on less often than would be expected. Another issue identified by this analysis is that the electrical meter for the building measures both the import and export as positive values. That means that in midsummer, once the solar PV system charges the battery, any extra solar PV power produced is sent to the grid at the same cost as power being used. Any future solar installation should verify that the grid-facing meter is bidirectional.

- The heat pump offsets the use of 535 gallons of diesel over the course of one year, based both on calculations and on the amount reported by the local operator. The boiler in the building used approximately 504 gallons of fuel during the same time period. In other words, the fuel usage approximately halved after the heat pump became operational. If the control is reprogrammed so that the heat pump turns on consistently, it is possible that additional savings will be realized.

- The economic analysis indicates that the system payback periods are in the 20- to 30-year range. The net present values for a 20-year time frame indicate that these systems are only economically viable for communities through grants. Fuel prices increasing by more than 25%, or subsidized (with PCE) electricity prices decreasing by more than 25%, make the GSHP a more viable option economically. Unsubsidized electricity prices increasing by 25% or more make a solar PV system with battery storage nearly economically viable after a 20-year period for commercial or school buildings that are not eligible for subsidies.

- The economic analysis did not take into account that some portions of the system(s) may last longer than 20 years, such as the underground portion of the GSHP. A longer-term perspective may be more financially favorable.
- The recommendation is that future systems, if elected for installation, be added as the building is being constructed. Retrofits on the mechanical system after it is in place lead to overly complicated systems that may perform less well than if installed from the get-go.

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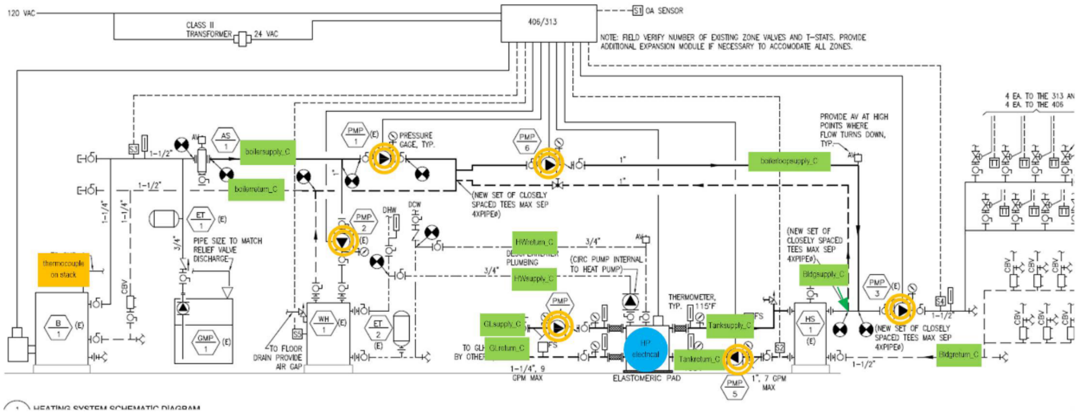
Appendix A. Schematic of Mechanical Room System

Following is a more detailed schematic of the mechanical room system as well as measurement locations of the data system.



Appendix B. Weather Data

The Federal Aviation Administration (FAA) weather station in Ruby (station: PARY) is located at the airport at the top of the ridge above Ruby, and the outdoor temperatures mentioned in this report come from that source. This becomes important when outdoor temperatures by the tribal building are discussed. In interior Alaska, an inversion is often present in winter when clouds are not present. This means that higher elevations experience warmer temperatures than lower elevations, and the difference can be 20°F or even 40°F. Thus, the temperatures from the Ruby METAR station used in this report are representative of airport temperatures but may potentially be 20°F or more warmer than those at the tribal building in wintertime when an inversion is present. In other words, the temperature record for Ruby Airport is expected to approximate the temperature at the tribal building to within 0°F to 20°F. Additionally, the FAA weather station at Ruby experienced an outage December 26, 2021–January 4, 2022, and February 12–17, 2022, and that missing data were replaced with data from the city of Galena.

There is an identical FAA weather station at the airport of the city of Galena, Alaska (station: PAGA). Galena lies 40 miles due west of Ruby, also on the Yukon River (50 river miles downstream), and the airport is at the elevation of the city, not on a hillside. In wintertime when inversion occurs, the METAR report from Galena airport, 40 miles away but at similar elevation, can be a good proxy for the outdoor temperature at the Ruby tribal building rather than the FAA weather record from Ruby airport, which is nearby but significantly higher than the tribal building. The Galena weather data were used for the periods when the Ruby data were missing.

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