# Feasibility Study for NT Energy Solar Potential

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# FOREWORD

This report presents the findings of a feasibility study conducted to assess the potential for a 5 MW solar power plant installed within the Northwest Territories' North Slave (Snare) and South Slave (Taltson) hydro grid systems. The study examines the economic and environmental implications of the two proposed plant locations. It evaluates metrics involved with installation, including costs, operational and maintenance expenses associated with the operation of the solar plant, greenhouse gas (GHG) emissions reductions, and time until installation costs are recouped. This report also considers the scenario where the existing Diavik mine’s solar plant is repurposed for another solar installation in the Northwest Territories (NWT).

This report aims to provide NT Energy with an analysis of the economic and environmental benefits of integrating utility-scale solar energy into each region's power grid. A thorough analysis of potential costs and benefits of the proposed 5 MW plant is given.

The study adopts a two-pronged approach in keeping with Northern Energy Innovation's commitment to providing unbiased and transparent research. The internationally recognized RETScreen Clean Energy Management software provides an established framework for evaluating potential installations, while a ground-up approach includes a more detailed breakdown of analysis components.

# DISCLAIMER

This report has been prepared as the second phase of a feasibility study to assess the potential for a 5 MW solar power plant within the Northwest Territories’ North and South Slave hydro grid systems. The results and analyses presented herein are based on historical data, reasonable assumptions, and calculations performed using RETScreen Clean Energy Management software.

While every effort has been made to ensure the accuracy and reliability of the information, the findings are subject to the limitations of the data sources and tools employed. Assumptions regarding solar irradiance, equipment performance, and economic parameters have been outlined in the report and should be reviewed carefully by stakeholders.

The report is intended to provide a high-level analysis and should not be used as the sole basis for investment, engineering, or operational decisions. Stakeholders are advised to undertake more specific investigations into project costing, as well as develop technical models of the proposed solar plant, and how it may integrate into existing electrical infrastructure and generation resources before proceeding with implementation.

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# 1 INTRODUCTION

The Northwest Territories (NWT) faces unique energy challenges, including a reliance on diesel fuel to fully meet electricity generation needs. The high costs of diesel-based electricity production and the resulting greenhouse gas (GHG) emissions make integrating renewable energy sources a potentially valuable addition to NWT's regional grids. This study explores the potential for NT Energy to implement a 5 MW solar photovoltaic (PV) power plant in either of the North Slave (Snare) or South Slave (Taltson) regional grids. Each possible location is evaluated with respect to economic feasibility and environmental impact.

In 2022, the NWT relied on hydro power plants to supply 75% of the territory's electricity [1]. See Figure 1 for a summary of the generation sources used in the NWT.

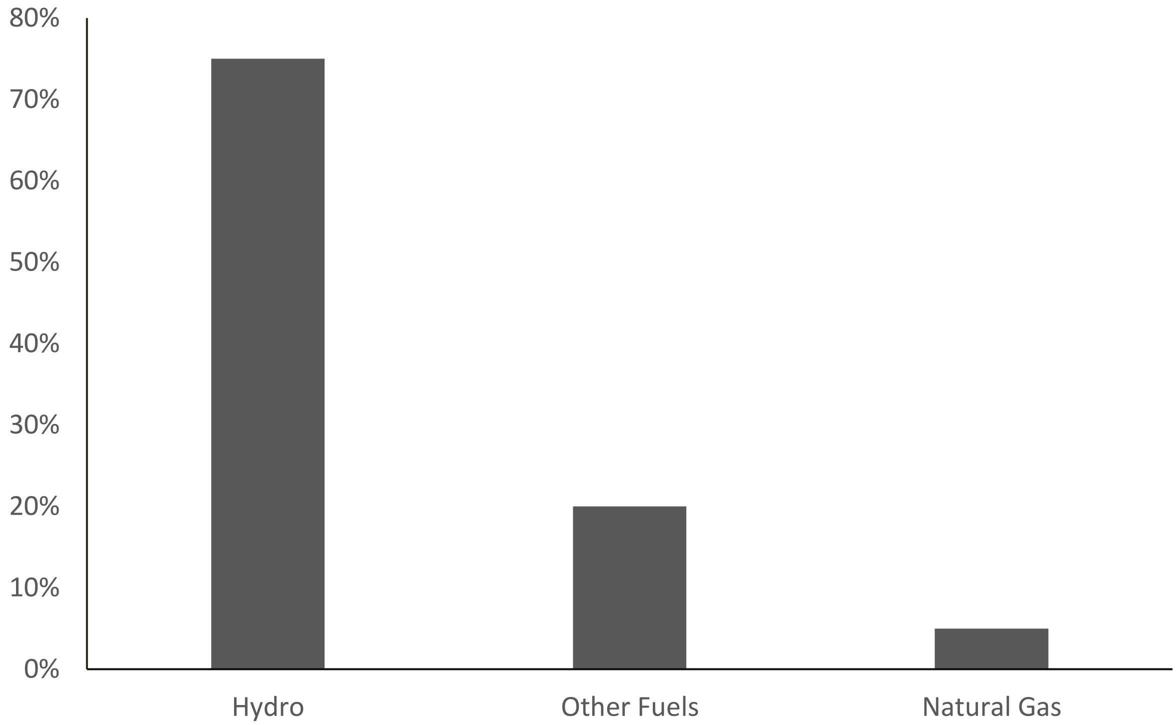


**Figure 1. Sources of electricity production in the NWT in 2022. Other Fuels include fuel oil, diesel, petroleum coke, and still gas. Note that these sources are considering all the NWT, not solely the North and South Slave grid systems. Source: [1].**

Since 2022, drought conditions have led to low water levels in the Snare River, resulting in a loss of hydro power in the North Slave region that has had to be made up with diesel generation. In 2022 – 2023, nearly half of the North Slave's power was generated with diesel [2]. Figure 2 shows the increase in energy output required by the Jackfish diesel plant following the beginning of drought conditions in 2022.

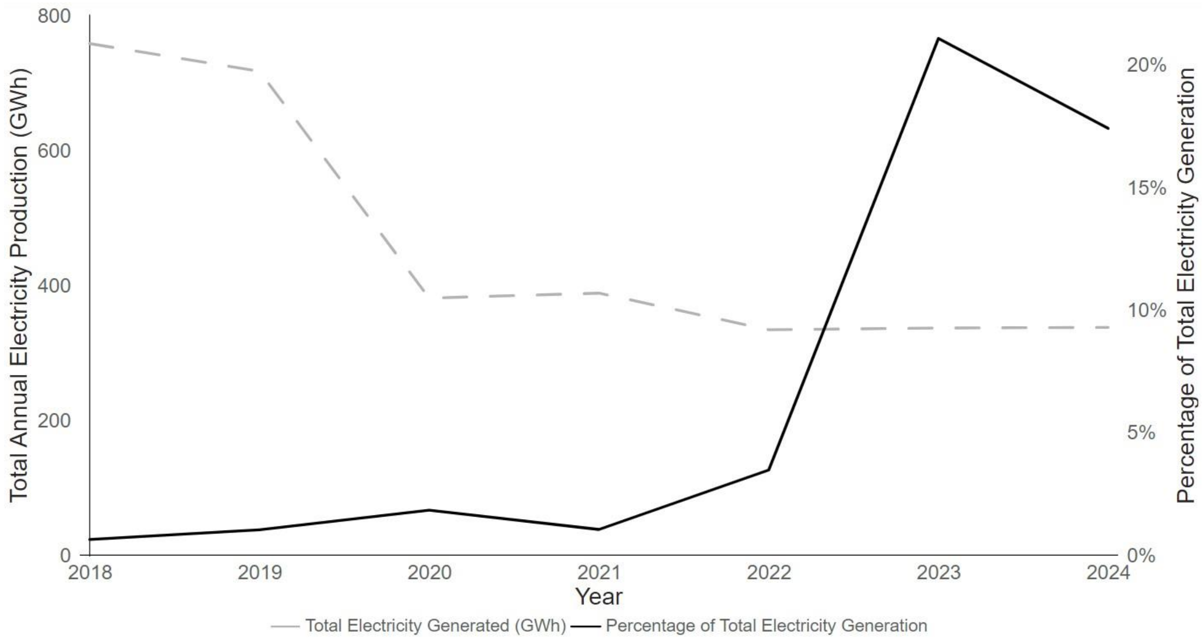


**Figure 2: Total electricity production in the NWT alongside the percentage of that production made up by the Jackfish Diesel plant. As total electrical production falls due to a reduction in hydro availability, the Jackfish diesel plant has had to increase its output. Total annual electricity production in 2023 and 2024 is a projection made in 2022.**

The large increase in diesel usage has led the Northwest Territories Power Corporation to file for a deferral account, citing "unanticipated and extraordinary operating and maintenance costs incurred due to low water conditions on the Snare River." [3]

While there have been solar projects spread throughout the territory, solar power made up less than 1% of the territory's electricity production in 2021 [4]. One solar plant that is in operation is located at the Diavik Diamond Mine. The mine is set to close in 2029 and there is potential for components of the solar installation to be repurposed for use in a grid-connected solar plant. A solar plant in the North Slave, while beneficial during normal conditions, could serve as a useful generation source during drought years and beyond. Variables including reduced hydro reliability, increased reliance on diesel, declining solar module costs, and the possible re-purposing of the Diavik Mine's solar components, could all contribute to the feasibility of a utility-scale solar installation on the South or North Slave grids.

In 2013, an analysis of solar potential in NWT determined that installation costs for solar were between \$9,000 - \$14,000 [5]. This price was deemed prohibitive to building solar projects in the territory at that time, although it was mentioned that the technology had decreased in cost in the decade before 2013. Figure 3 shows that the levelized cost of energy (LCOE) of solar has since continued to decrease, dropping 89% in the period between 2009 and 2019 [6]. This steep decline in cost warrants a re-evaluation of the potential of solar in the NWT.

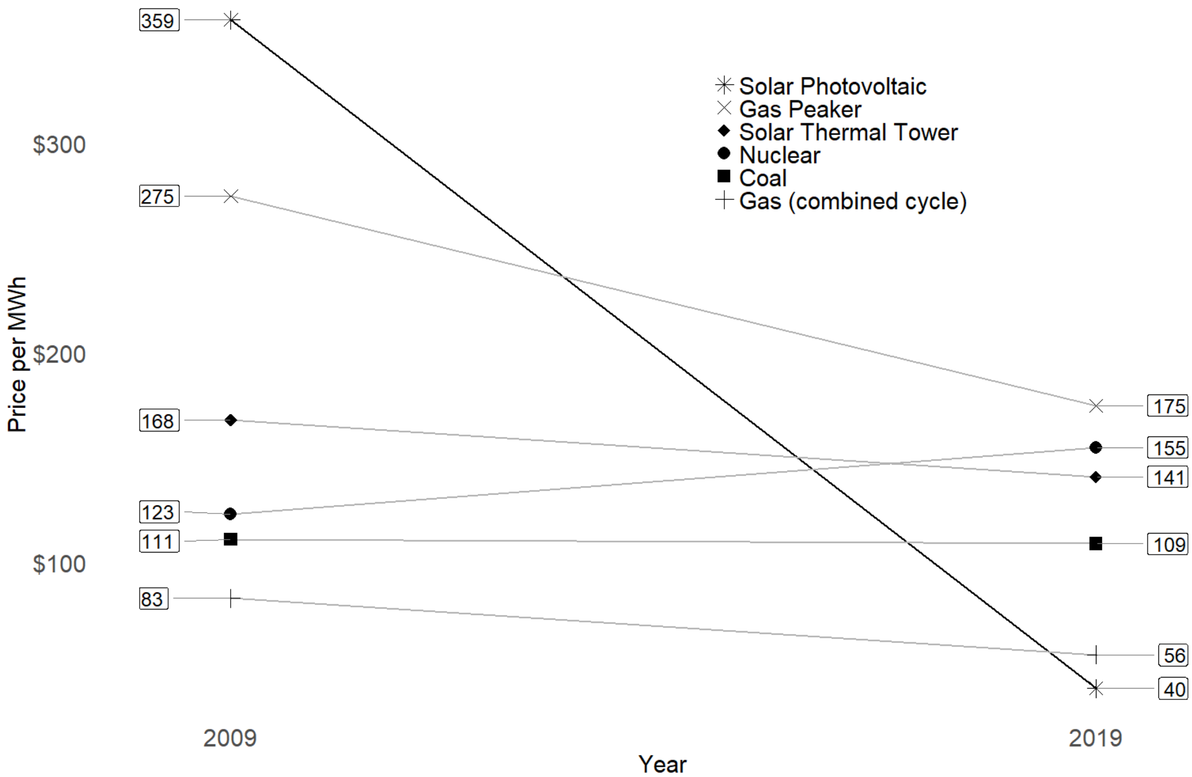


**Figure 3. The levelized cost of energy from new power plants by type. LCOE includes installation and operating costs. Source: [6]**

Two potential solar plant locations have been identified: Yellowknife for the North Slave system and Pine Point for the South Slave system. These locations were picked based on their proximity to existing infrastructure and land availability. This assessment includes an analysis of capital and operational costs, fuel displacement potential, GHG reductions, and the point at which the value of the energy exported meets the installation and ongoing operational costs. The viability of repurposing the Diavik Mine's solar components is also investigated.

Two approaches will be taken in this study; an approach using the internationally recognized RETScreen software, and a "ground-up" approach based on manual calculations using well-established estimates.

The findings presented herein aim to equip NT Energy with the sufficient information to determine the viability of a solar project at either location, enabling deeper analysis of the techno-economic feasibility of such a plant at either location. This report builds upon the findings of the preliminary Phase 1 report which was submitted in November 2024 to NT Energy.

# 2 ASSUMPTIONS

Many assumptions have been made to arrive at reasonable results at this stage of the project. A summary of these assumptions is given below:

1. Seasonal variation in solar generation has been modeled using historical weather and irradiance data with the assumption that these trends, on average, continue.
2. The electricity produced by the solar plant in the South Slave grid system will offset LNG electricity production entirely, maximizing fuel displacement. Communicated by NT Energy [7].
3. Harsh climatic conditions typical of the NWT, such as cold temperatures and snow coverage, have no additional effect on long-term performance and lifespan of the solar panels and other system components beyond what is already captured in the estimates used.
4. A flat 28% increase is applied to estimates that are based on southern jurisdictions. This is to reflect the increased cost expected with northern projects [8].
5. Carbon dioxide equivalency calculations are based on standard emission factors for diesel and LNG power generation. They do not consider production and transportation of these fuels.
6. The existing electrical grid infrastructure is sufficient to support integration of renewable energy with minimal upgrades.
7. Community stakeholders and end-users will support renewable energy projects.
8. Cost estimates do not account for any grants, subsidies, or loans.
9. Solar plant maintenance and cleaning is performed regularly enough that there is no drop in performance from snow or dust accumulation.

# 3 METHODOLOGY

## 3.1 CONFIGURATION SELECTION

An important factor in determining the feasibility of a solar installation is the characteristics of the panels and how they are arranged. During the research process, certain solar panel types and configurations were investigated for their applicability in northern environments. An analysis of the factors considered in the configuration of the plant is given below.

### 3.1.1 Tracking Systems

Tracking systems enable the solar panel to rotate along one or two axes to follow the path of the sun across the sky, leading to more efficient collection of irradiance and greater energy production. Efficiency gains increase with the number of axes, but so does the installation and maintenance costs. The subarctic environment of both the North and South Slave grid systems can increase the cost of tracking systems beyond what is observed in southern regions, as the low temperatures, snow accumulation, high winds, and cloudy weather can all impact the ability of the systems to accurately track the sun. Conversely, high latitude locations benefit from tracking systems, particularly dual axis, due to the wide range in sun elevation throughout the year, with various studies finding efficiency gains from 4% to 68% compared to fixed-axis systems [9] [10].

“High latitude” areas like Vermont were deemed as regions where dual-axis systems were worth the cost [11]. However, when an algorithmic approach based on the Köppen-Geiger climate classifications was used to determine the overall value of tracking systems globally, subarctic regions like that of the North and South Slave region were determined to be not financially viable [12] [13]. The increased costs of projects in such climates, like travel, accommodation, shipping, and labour costs, as well as the increased maintenance costs associated with tracking systems in such environments, such as snow removal and reinforced support structures, as well as the increased wear and breakdown of moving parts in extreme cold temperatures, negates the potential gains of tracking systems. Due to these findings, this report considers only fixed-axis configurations.

### 3.1.2 Bifacial and Monofacial Panels

There are two broad types of solar panel: monofacial (single-sided) or bifacial (double-sided). Similar to tracking systems, bifacial panels offer increased power output but cost more than the standard monofacial panels. Also similar to tracking systems, studies have found that high latitude, subarctic environments like that of the NWT provide additional efficiency gains for bifacial panels [14]. Unlike tracking systems, there are few drawbacks to bifacial panels besides the increased upfront cost.

Compared to monofacial panels, bifacial panels require additional manufacturing and materials, leading to a higher average cost per installed watt [15]. Although having a higher upfront cost, bifacial panels can produce more energy than monofacial panels and shorten break-even times on investment. A bifacial solar PV plant can generate the same amount of energy with smaller plant area, which may lead to reduced installation costs. Bifacial panels are often more efficient and cost-effective for utilities at scale, especially in locations with snow where the increased ground reflectance can lead to greater irradiance captured by the bifacial module [16]. Table 1 gives an overview for important information on monofacial and bifacial panels.

**Table 1. Comparison of monofacial and bifacial solar panels. Source: [14] [15] [17] [18]**

| Category | Monofacial Panels | Bifacial Panels |
|---|---|---|
| Cost per Watt ($/W), by panel technology | $0.25 - $0.27 (c-Si),<br>$0.28 (CdTe),<br>$0.48 (CIGS) | $0.30 (IBC),<br>$0.32 (PERC+),<br>$0.35 (nPERT),<br>$0.37 (HJT),<br>$0.67 - $0.77 (TOPCon) |
| Energy Yield Increase | Baseline (0%) | 5% - 30% higher than monofacial in fixed-axis tilted configurations;<br>>95% higher than monofacial in fixed-axis vertical configurations |
| Market Share Projection (out to 2032) | Expected to decline as bifacial grows | Projected to reach 85% of the market |
| Optimal Installation Environments | General rooftop and utility-scale installations | High-albedo areas (snow, sand, reflective surfaces), vertical installations |
| Capital Cost Reduction (Next Decade) | ~30% decrease expected | ~40% decrease expected |

To analyze the differences in cost between monofacial and bifacial panels, NREL estimates for the cost of monofacial and bifacial solar modules are used [19, p. 17] sourced from Figure 12 in that document. The cost differences between monofacial and bifacial modules with respect to different cell technologies are given in Table 2.

**Table 2: Module cost differences between different bifacial cell technologies and monofacial PERC type module.**

| Bifacial cell technology | Bifacial module technology less monofacial PERC module | |
|---|---|---|
| | Absolute Difference [2019 $USD/W] | Proportional Difference [%] |
| PERC (Passivated Emitter Rear Contact) | 0.01 | 3.84 |
| PERC/PERL (Passivated Emitter Rear Locally Diffused) | 0 | 0 |
| SHJ (Silicon Heterojunction) | 0.02 | 7.41 |
| IBJ (Interdigitated Back Contact) | 0.02 | 7.41 |

The PERC monofacial modules are 7.41% cheaper than the SHJ or IBJ bifacial modules, 3.84% cheaper than the PERC bifacial modules, and the same expense as the PERC/PERL bifacial modules. The most expensive difference of 7.41% will be used in the following analysis. There is a trade-off between the increased installation costs associated with the larger plant area for a 5 MW monofacial solar PV plant, and the decreased installation costs associated with the cheaper modules. This trade-off is plotted in Figure 4, developed using the NREL cost estimates detailed later within Section 3.2.2.1 in Table 3.

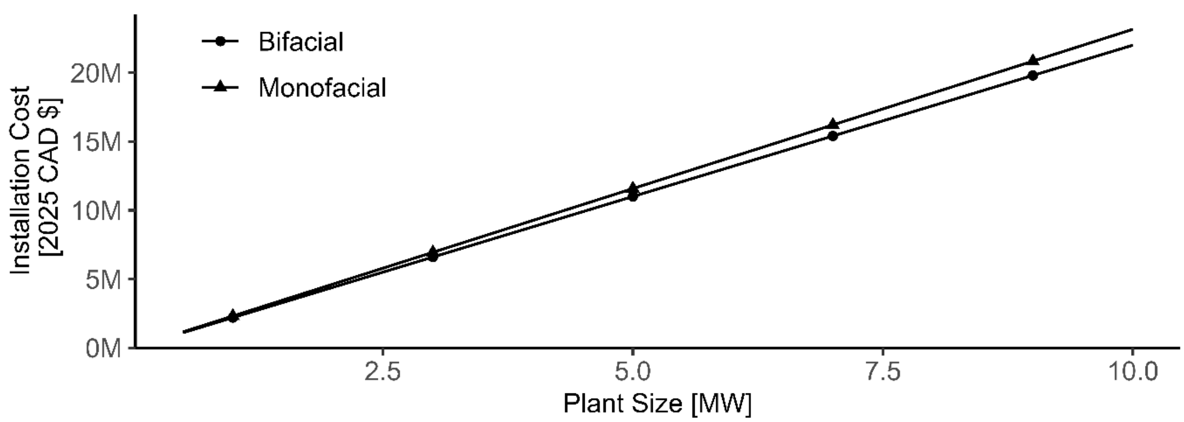


**Figure 4: Comparison of installation costs for solar PV plants with a monofacial and bifacial configuration.**

The bifacial configuration is cheaper than the monofacial configuration at all plant sizes considered (0.5 MW to 10 MW). The additional costs required to ensure the monofacial plant emits the same amount of energy as the bifacial plant outweigh the savings from the cheaper monofacial modules. It is also important to note that this analysis does not consider the efficiency gains that bifacial modules will have in regions with large amounts of snowfall. It is likely that the lower installation costs, along with the greater performance given by bifacial modules, makes them a clear choice for a sizable solar PV plant in the NWT. In this study only bifacial panels will be considered for both modeling approaches.

### 3.1.3 Effects of Solar PV on South and North Slave Grids

The two possible site locations of Pine Point and Yellowknife, on the South and North Slave grids respectively, present two different ways in which a solar PV plant could add value. On the South Slave grid, currently the existing hydro resources are more than sufficient to meet demand. However, it is expected that mining operations will begin in a matter of years which will exceed the current hydro capacity [7]. It is assumed that Liquified Natural Gas (LNG) generation will be installed to meet the increased demand from the mine, and a 5 MW solar plant can directly offset the LNG generation [7].

The situation on the North Slave grid is more complex. Currently, the grid is served by a mixture of hydro and diesel generation. Generally, hydro resources have been sufficient to meet most of the grid's needs. However, droughts have occurred at a frequency of roughly two years in every ten over the past two decades, and in drought years the amount of diesel generation on the grid rises greatly [7]. There are two distinct scenarios in which to consider the effects of a solar PV plant installation, a drought year or a non-drought year. Figure 5 shows the hourly power generated from the Jackfish diesel plant from the years 2019 through 2024. Note that the Jackfish diesel plant accounts for most of the diesel energy generated on the North Slave grid.

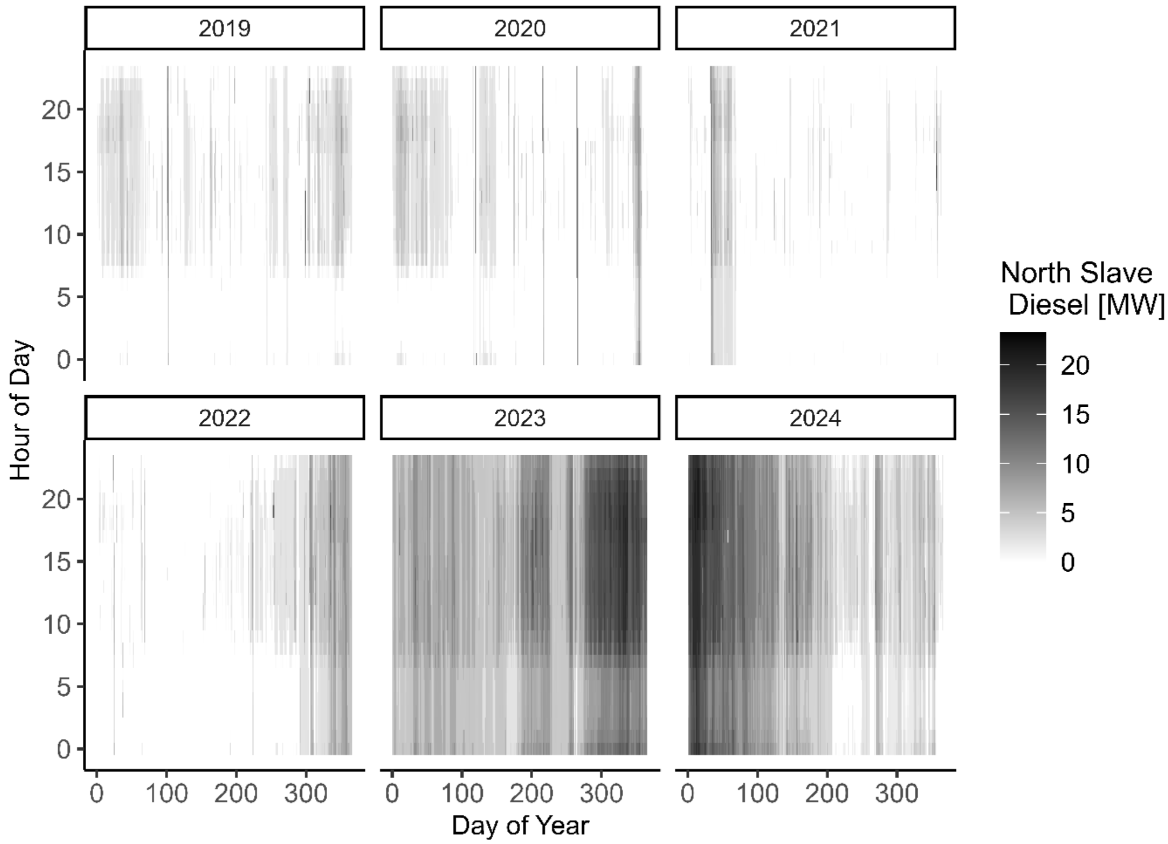


**Figure 5: Heatmap of intra-day diesel power generation on the North Slave system year over year.**

In drought years like 2023 and 2024, the demand is spread more uniformly through the day, whereas in non-drought years there are occasions when the diesel load spikes uniformly, but generally diesel generation is limited to late morning to late evening hours. Even in drought years, the intensity of the heatmap is greatest during this late morning to late evening time-period. A solar plant that, on average, maximizes power production during this late morning to late evening period, may provide a stronger opportunity to reduce diesel generation than a solar plant that ramps up energy production until solar noon and then declines.

The effects of wildfire smoke on the energy potential of solar PV are worth noting. In 2023, severe wildfires caused widespread evacuations and devastation throughout the NWT [20]. Smoke from wildfires not localized to the NWT also can affect solar irradiance. Generally, the power reduction due to wildfire smoke changes with respect to the solar cell technology used in the solar panel. The effects of smoke on solar energy potential for four different cell technologies was studied in [21], and it was shown that depending on the amount of pollution in the sky, between-cell-technology differences ranged between 4% and 17%. Overall solar energy production was shown to be reduced between 23% and 84%, depending on cell technology and the relative amount of pollution in the air. A study of the effects of wildfire smoke across multiple sites found an average reduction of 8.3% in solar PV performance [22]. Both the RETScreen and ground-up approaches undertaken in this study employ averages of multiple years of solar irradiance data to generate estimates for annual energy generation. The effects of wildfire smoke are assumed to be captured within these averages, though future study may prove useful to determine the specific effects of wildfire smoke.

### 3.1.4 South and North Slave Configurations

As mentioned earlier, all considered panels are bifacial. To determine the optimal panel tilts for both the South and North Slave locations, the solar irradiance model described in Section 3.2.2.2 was employed to calculate the average annual energy output at a variety of panel tilts over a period of 20 years. These simulations identified an optimal panel tilt of 50° and 52° in Pine Point and Yellowknife respectively. Results for this simulation are provided in Appendix 8.2.

The investigated plant configurations for the South Slave grid are:

- 100% west-facing vertical bifacial fixed-axis modules.
- 100% south-facing 50° tilted bifacial fixed-axis modules.
- 70% west-facing vertical bifacial + 30% south-facing 50° tilted bifacial fixed-axis modules.

The investigated plant configurations for the North Slave grid are:

- 100% west-facing vertical bifacial fixed-axis modules.
- 70% west-facing vertical bifacial + 30% south-facing 52° tilted bifacial fixed axis.

These configurations were chosen to evaluate scenarios which may maximize total annual solar energy production, provide a more optimal generation profile for the load demands on the North and South Slave grids, and strike a balance between these two goals. The vertical configuration especially bears investigating in the northern context; vertical panels reduce the need to clear snow and better capture the Sun's rays when they are at relatively smaller angles to the Earth's surface (i.e. when the Sun is lower in the sky).

To demonstrate the logic behind these configuration choices, for a given west-facing vertical bifacial configuration, averaged daily energy profiles are plotted against the average daily diesel profile from the Jackfish plant, normalized for direct visual comparison. See Figure 6.

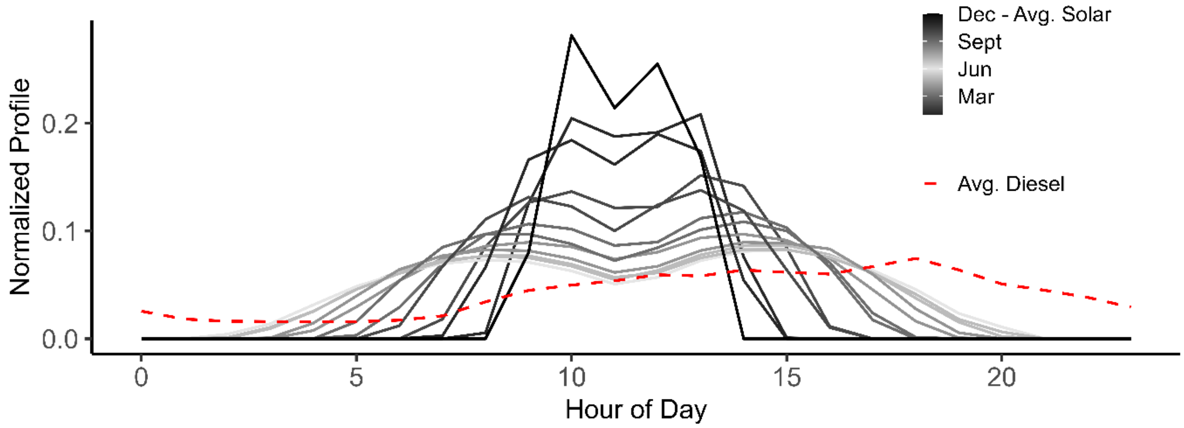


**Figure 6: Normalized daily output cycle of the Jackfish diesel power plant, averaged across 2018-2024, plotted against the monthly normalized solar energy potential of a bifacial vertically tilted solar plant.**

As with Figure 5, Figure 6 shows that the prevailing shape of the daily diesel load curve ramps from the early morning to the late evening. A solar profile can be targeted to have more solar energy generation occur during this period and offset greater amounts of diesel on average. The normalized energy potential of the west-facing vertical bifacial configuration shown in Figure 6 captures a greater amount of solar energy later in the day, suitable for the diesel profile. Note the "dip" in the solar profiles about solar noon, when the sun is directly overhead of the panels. This dip is why the mixed configuration with some ratio of vertical bifacial and tilted bifacial modules could be useful. A greater amount of energy could be generated about the solar noon by the flatter panels, creating a smoother profile that is more predictable and consistent, while also capturing greater amounts of solar energy.

## 3.2 DATA COLLECTION AND SOURCES

### 3.2.1 RETScreen

The primary data input for the analysis was daily solar irradiance, specific to the proposed location of the solar plant within the North and South Slave regions. For the North Slave region, that location was Ptarmigan mine (Lat: 62.52, Lon: -114.20). For the South Slave region, that location was Pine Point (Lat: 60.88, Lon: -114.43). Historical datasets formed the basis of the study, with the RETScreen Expert software being the primary software used to perform calculations and analyses on top of this data. The RETScreen Expert software enabled the evaluation of economic feasibility and environmental impact by inputting variables such as system size, panel type, and operational parameters. RETScreen outputs included installation and operation costs, energy generation potential, revenue, and GHG reductions. Additional calculations were completed within Microsoft Excel to provide additional metrics such as the number of years until the project paid for itself (break-even time) and amount of fuel displaced.

RETScreen accesses global meteorological databases such as NASA's Surface Solar Energy dataset and the National Renewable Energy Laboratory (NREL) weather files for solar resource data. The software also has a variety of built-in databases for products (i.e. solar panels) and typical project costs (i.e. installation, operation, maintenance) that streamline analysis.

#### 3.2.1.1 External Parameters

Certain parameters had to be sourced outside of RETScreen and were consistently used between the two different methodologies. A cumulative inflation rate of 7% was applied to adjust Canadian dollar values to account for RETScreen's default base year of 2022 [23]. An increase of 28% was applied to installation and O&M costs to reflect the increased price of goods and services in northern Canada [8]. For the price of electricity, $0.37/kWh was cited as the end-user cost of electricity in Yellowknife and $0.47/kWh was cited as the end-user cost in Hay River [24] [25], which differed from the $0.41/kWh used in both locations in the ground-up approach. Average solar panel potential efficiency was found to be 20.5% [26].

To determine the total GHG emission reduction of the solar installations, the GHG emissions of both diesel and solar energy production had to be determined. When burned in combustion, diesel fuel emits 0.27 $tCO^2$/MWh of power [27]. While solar doesn't actively produce GHGs when producing power, the upstream processes of material extraction, module manufacturing, and installation combined with operational maintenance and the downstream process of decommissioning and disposal result in GHG emissions of 0.05 $tCO^2$/MWh of power produced [28]. RETScreen provides a GHG emission value for natural gas in the NWT as 0.367 $tCO^2$/MWh.

RETScreen states that bifacial models "can add about 2% to 5% to the overall photovoltaic system cost." According to the sources include in Table 1, however, there exists a variety of solar panel cell technologies, leading to a wide range of costs. On average, the cost of monofacial panels is $0.34/kW and the cost of bifacial panels is $0.412/kW, making bifacial panels 21% more expensive.

### 3.2.2 Ground-Up

#### 3.2.2.1 Installation, Operation, and Maintenance Costs

Every year the National Renewable Energy Laboratory (NREL) publishes a cost benchmark of important variables involved in the construction of solar PV plants in the United States. The most current available report was used to inform initial analyses for solar PV components [26]. Estimates for the cost of solar components for a utility-scale PV installation were sourced from the NREL report. The NREL methodology calculated a Minimum Sustainable Price (MSP) and a Modeled Market Price (MMP). The MSP can be interpreted as “the minimum price a company needs to charge to remain financially solvent in the long term based on the minimum sustainable prices of all inputs including minimum sustainable profit margins” [26, p. 6]. In contrast, the MMP can be interpreted as “the actual cash sales price the company charges in the given benchmark period” [26, p. 6]. In this analysis the MMP cost benchmarks are employed as they are more likely to reflect actual market conditions. A summary of the component costs used in this report for solar PV installation is given in Table 3, which were converted to a uniform metric of $\$/kW_{dc}$ using information in the data file provided with the publication [29], where $kW_{dc}$ corresponds to the rated power of the solar PV modules before being converted to $kW_{ac}$ through an inverter. The original figures quoted in [26] and [29] are given in 2022 US dollars. To adjust for inflation, an inflation factor of 1.07 was used to convert to 2024 US dollars [30]. Then a current conversion rate of 1.42 between US and Canadian dollars was used to adjust to local currency using the most recent exchange rate of 1.42 US dollars for every Canadian dollar. Finally, it is generally understood that in the Canadian northern territories (Yukon Territory, NWT, and Nunavut) costs for goods and services are higher than throughout the southern Canadian provinces. To reflect the increased cost of a solar installation in the NWT, cost benchmarks in 2025 Canadian dollars were increased by 28% [8]. The value of the energy generated by the solar PV plant was taken to be an average of $0.41/kWh [31]. The same GHG emission coefficients are used to calculate GHG emissions as were used in the RETScreen approach.

**Table 3: NREL costs associated with solar plant installation.**

| Solar Plant Component | Cost (2025 CAD $) |
|---|---|
| Module ($/kW$_{dc}$) | 723 |
| Inverter ($/kW$_{dc}$) | 93 |
| Electrical Balance of System (EBOS) ($/kW$_{dc}$) | 342 |
| Office work ($/kW$_{dc}$) | 128 |
| Other ($/kW$_{dc}$) | 261 |
| Structural Balance of System (SBOS) ($/m$^2$) | 40 |
| Fieldwork ($/m$^2$) | 94 |

The costs in Table 3 were ultimately derived from a set of assumptions. NREL created utility-scale cost benchmarks assuming a 100 MW single-axis tracking solar PV system, using 20.5% efficient bifacial monocrystalline silicon modules [26, p. 28]. NREL notes that the "per-unit cost results are meant to be generally applicable to systems with PV sizes between about 50 and 200 MW". This is considerably larger than the smaller scale 5-10 MW PV system envisioned for the NWT, however at this project stage the cost benchmarks will be used as-is.

The estimates for the solar PV system costs in Table 3 assume a single-axis tracking system. A fixed system is assumed in this report due to challenges with tracking systems in high latitudes. The structural balance of system figure quoted in Table 3 was revised to subtract any components needed for a single-axis tracking system. However, other costs could be hidden in the NREL benchmarks and not as easily eliminated. Thus, any resulting cost estimates may be inflated with respect to a fixed tracking system

The operation and maintenance (O&M) costs were also sourced from the NREL report on benchmark costs. The O&M costs after applying the inflation factor of 7%, the USD to CAD exchange rate of 1.42, and the 28% northern Canada cost increase are $32.25/kW$_{dc}$/year. Within this cost estimate, NREL estimates that $4.84/kW$_{dc}$/year are a result of cleaning. However, given these estimates are based on a national average, it is likely that the cleaning costs associated with clearing snow regularly from modules are underestimated relative to the amount of snow in the NWT. To account for this discrepancy, the average annual snowfall for Yellowknife was calculated to be 173 centimeters [32]. Comparing this figure to the average annual snowfall for all the American states, only three states receive a greater average annual snowfall, and is roughly double the average annual snowfall for an American state. Thus, the cleaning figure of $4.84/kW$_{dc}$/year is multiplied by two, resulting in a new O&M cost estimated of $37.09/kW$_{dc}$/year. However, if all panels are configured vertically then snow clearing is not as onerous as every module will not have to be cleared; for vertical configurations the \$32.25/kW$_{dc}$/year number is used to calculate O&M costs.

#### 3.2.2.2 Energy Potential

To calculate the energy potential of tilted surfaces, a well-known and straightforward model was employed, the isotropic diffuse model [33, pp. 91-92]. This approach breaks down solar irradiance into three components, a direct component normal to the tilted surface, a diffuse component, and the horizontal irradiance reflected from the ground onto the tilted surface. Global horizontal irradiance and diffuse irradiance data was procured from the NASA POWER web portal for the Yellowknife and Pine Point locations Hourly 2.4.9 version on 2025/02/07 [34]. The exact location of the Yellowknife and Pine Point locations are slightly different than those used in the RETScreen approach, however this will have a negligible effect on the irradiance data used in the modeling. The irradiance normal to the tilted surface can then be calculated subtracting the diffuse irradiance from the horizontal irradiance and multiplying by the ratio between the irradiance on the horizontal to that on the tilted surface. Details are provided in Appendix 8.3.

The irradiance values were then scaled by 20.5%, following the efficiency assumption of the panels used in the NREL benchmark report [26, p. 28], and then multiplied by an inverter efficiency of 96% [35, pp. 11-12]. Then the values were multiplied by the effective area of solar panel coverage in the solar PV plant to achieve a total in kWh. The effective area of the solar panels needed was calculated by taking the average size of the solar panel considered in the NREL cost benchmark and dividing it from the power rating of the panels considered in the NREL cost benchmark, getting a ratio of 206 W/m$^2$. Then, using the 5 MW$_{dc}$ sizing of the solar PV plant an effective area of 24245 m$^2$ was calculated for a bifacial installation.

When considering bifacial modules, the rear surface was assumed to have a power bifaciality factor of 70%, which assumes that under ideal identical conditions the rear panel on a bifacial module will produce 70% as much power as the forward panel. This is a conservative assumption; it aligns with estimates for p-type PERC (Passivated Emitter Rear Contact) cells [36] [37]. The 70% bifaciality factor also aligns with the panels installed in the Diavik mine solar PV plant [38]. However, for different solar panel technologies bifaciality factors higher than 90% have been reported.

The annual estimated energy production from the South Slave and North Slave sites were then multiplied by 92.5% as an estimate for transmission and distribution system losses in the NWT. The Canadian Energy Systems Analysis Research group estimated that total transmission and distribution losses through the nation are less than 10% [39, p. 5].

## 3.3 SCENARIO ANALYSIS

### 3.3.1 East-West Vertical Bifacial Fixed-Axis

Array configurations that would, if installed in more southern regions, result in a loss of power can instead provide solutions to the challenges of high-latitude, subarctic installations. Arranging bifacial panels vertically and facing East-West in these environments results in over 100% energy gains compared to a similar monofacial setup and 5% – 30% more than south-facing tilted monofacial panels [14, p. 385] [17, p. 2]. Large areas of snow-covered ground can reflect up to 75% of light back up to be collected by bifacial panels, compared to 20 – 30% for soil or vegetation [14, p. 386], and the effect of snow buildup on the panels themselves is mitigated by the sheer 90$^{o}$ angle of vertical panels, making East-West vertical panels suitable for the flat, snowy environment of the North and South Slave grids.

Vertical bifacial panels produce more energy than south-facing sloped bifacials from March through June [17, p. 10], and a study by the University of Alaska Fairbanks found similar annual electricity production between the vertical and sloped bifacial configurations, with the main difference being the yearly and daily generation profiles [17, p. 12], although this was with individual panels and not a utility-scale plant.

The increased cost of tracking systems, especially considering the additional costs involved with northern projects, is negated by the fixed nature of the vertical panels, and the optimal tilt angle for solar panels naturally increases as the distance from the poles decreases, meaning that vertical panels are closer to the optimal tilt the further north they are installed [14, p. 386]. However, care must be taken as to the location of nearby objects and other panels, as the potential for these items to cast shade onto the vertical panels is high. Important to note is the relatively flat ground and plentiful land available in the NWT, which provides more flexibility for solar plant configurations [40].

Vertical bifacial panels may also provide a better fit for the energy demands of northern communities. Due to the panels east-west orientation, this configuration results in a bimodal diurnal power output profile with a peak output in the morning and another in the evening, rather than a unimodal profile with a single peak around noon that is present with south-facing tilted systems.

RETScreen assumes all panels are monofacial and simply adds a "bifacial cell adjustment factor" to distinguish when a configuration has bifacial panels. The bifacial cell adjustment factor was set to 95% to simulate a bifacial panel, in which rear panels are known to be less efficient [18, p. 5], and a cost increase of 7.41% was added to the prices given by RETScreen to reflect the increased price of bifacial panels. There is the assumption that maintenance and cleaning of the solar panels is happening regularly enough that there is no drop in performance due to snow or dust accumulation.

### 3.3.2 East-West Vertical Bifacial Fixed-Axis + South Sloped Bifacial Fixed-Axis

A configuration of solely east-west vertical bifacial panels would provide a more distributed power production profile, but also a drop in power production when the sun is directly overhead. To keep producing power over solar noon, a configuration that makes use of both east-west vertical panels and south-facing sloped panels is considered. The combination of both vertical and sloped panels could provide a suitable middle-ground, where power production starts early, maintains through the midday, and continues into dusk. Research done at the University of Alaska Fairbanks showed that a ratio of 2.4 kW of vertical east-west panels to 1 kW south-facing sloped panels offset the most power demand for a simulated rural Alaskan community [17, p. 12].

It is important to note that RETScreen can only analyze one panel type per configuration, leading to the mixed configuration being calculated as a weighted combination of the other two homogeneous setups.

### 3.3.3 South Sloped Bifacial Fixed-Axis Ground-Up

South-sloped bifacial fixed-axis panels are a conventional configuration that would offer a unimodal power output profile. Unlike vertical east-west bifacial configurations, which maximize morning and evening output, south-facing sloped bifacial arrays follow a unimodal distribution, peaking around solar noon when the sun is directly in front of the array.

In northern regions, where the sun remains low on the horizon for much of the year, a steeper tilt angle can improve energy capture by increasing the exposure of the panels to the sun's rays. However, this also means that power generation during the morning and evening is reduced compared to east-west configurations. While south-facing bifacial panels can still take advantage of ground-reflected irradiance, the contribution is highly dependent on ground conditions, with snow significantly enhancing the rear-side energy gain.

However, one of the main challenges for sloped panels in northern environments is snow accumulation on the top surface. During the winter, bifacial panels produce up to 40% more electricity than monofacial panels [11, p. 1], suggesting that without the ability to collect light reflected off the ground, power output can be greatly impacted.

## 3.4 DIAVIK SOLAR PLANT CONSIDERATION

The cost to install the solar PV plant at the Diavik mine was over $4 million (M), with O&M costs around $0.5M dollars annually [41]. Repurposing components from this 3.5 MW plant for the North or South Slave locations could reduce the upfront costs of purchasing new solar panels. The solar installation at Diavik was completed in 2024 and is set to fully close in 2029, using up 5 of the panels' 30-year linear power performance warranty which guarantees less than 0.45% performance degradation after the first year [38].

While the supplier of the Diavik panels provided the degradation rate, NREL also provides a thorough study of industry-wide degradation rates for both modules and inverters. NREL estimates that for older solar PV modules, a 0.7% loss in performance is expected year over year for the first 10 years of operation [42]. However, this analysis was completed in 2012 for older solar module technology and installations, focusing on monofacial panels. An updated analysis for modern bifacial panel technology was completed in 2024 and demonstrated that degradation may be higher with the current technology [43]. NREL completed a 2024 study of the year-over-year performance loss for the fleet of American PV systems [44]. This study concluded that a broad 0.75% yearly degradation rate was an adequate assumption for solar PV systems. Thus, a 0.75% value will be used to estimate the year-over-year wear on the Diavik solar PV plant, resulting in a rated power value of 3.37 MW at the end of the 5 years.

The equivalent cost of the Diavik solar module and inverter components as per Table 3 are calculated and subtracted from the installation cost for the 5 MW solar PV plant on the North Slave or South Slave grids. Then, the effects of 3.37 MW of 5 MW worth of power generation components with an additional 5 years of wear are calculated. This scenario is contrasted with another where all plant components are installed with no wear (new). The trade-off between the reduced costs to install the new PV plant with the Diavik panels against the reduced power production is demonstrated. Of consideration is the cost of dismantling the needed Diavik plant components and then transporting them to the new site. Many variables are at play to accurately evaluate this, and not enough specific information exists to reasonably estimate these costs currently. The cost of disassembling the Diavik plant and transporting the panels is difficult to quantify without working directly with a logistics supplier with expertise in the Canadian north. However, the analysis will show a range of viable values for dismantling and transportation costs.

Additionally, RETScreen was used to produce lifetime power generation and revenue values for the different configurations based on whether they incorporated the Diavik panels. The 0.7% degradation rate was applied to maximum power capacity and the resulting capacity was input into RETScreen as the plant size to obtain that year's electricity generation and revenue potential. This process was repeated for a period of 30 years to get the lifetime impact of the Diavik panels. Results are displayed in Figure 11 and Figure 12.

# 4 RESULTS

## 4.1 RETSCREEN

### 4.1.1 South Slave

All three configurations were considered for the South Slave solar plant, as the main consideration was maximum production of energy. The considered configurations align with the discussion in Section 3.3; all modules are bifacial, and are tilted vertically, or at 50°, or a mixture of both (70% vertical modules and 30% tilted modules at 50°).

**Table 4. Output from RETScreen for the South Slave potential solar plant.**

| | Vertical Bifacial | Mixed Bifacial | Sloped Bifacial |
|---|---|---|---|
| Initial Cost ($, millions) | 13.72 | 13.72 | 13.72 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 | 0.19 |
| Electricity Export Revenue ($, millions/year) | 3.2 | 3.2 | 3.3 |
| Electricity Exported (MWh) | 6,754 | 6,836 | 7,028 |
| Break-Even Time (years) | 4.6 | 4.5 | 4.4 |
| GHG Emissions Reduced (tonnes/year) | 2,305 | 2,398 | 2,333 |
| LNG Displaced (Litres, millions) | 2.365 | 2.394 | 2.461 |

| | Vertical Bifacial | Mixed Bifacial |
|---|---|---|
| Initial Cost ($, millions) | 13.72 | 13.72 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 |
| Electricity Export Revenue ($, millions/year) | 2.7 | 2.8 |
| Electricity Exported (MWh) | 7,392 | 7,457 |
| Break-Even Time (years) | 5.3 | 5.3 |
| GHG Emissions Reduced - Drought Year (tonnes/year) | 1,749.0 | 1,764.3 |
| GHG Emissions Reduced - Non-Drought Year (tonnes/year) | 349.8 | 352.9 |
| Diesel Displaced - Drought Year (Litres, millions) | 2.0 | 2.0 |
| Diesel Displaced - Non-Drought Year (Litres, millions) | 0.399 | 0.403 |

### 4.1.2 North Slave

A vertical bifacial and a mixed configuration was considered for the North Slave, as a main concern was the ability of the solar installation to offset demand from the Jackfish diesel plant. Similar to the South Slave system, the all-vertical configuration has lower annual O&M costs than the mixed configuration.

The solar plant in the North Slave grid aims to offset the increasing diesel generation that has been occurring to make up for insufficient hydro power during drought years. Due to vertical panels possessing a bimodal daily generation profile that better aligns with the demand seen at the Jackfish diesel power plant, two solar panel configurations were considered: vertical bifacial and a mix of vertical bifacial with sloped bifacial at an angle of 52 degrees.

**Table 5. Output from RETScreen for the North Slave potential solar plant.**

| | Vertical Bifacial | Mixed Bifacial |
|---|---|---|
| Initial Cost ($ millions) | 13.72 | 13.72 |
| Operation and Maintenance ($ millions/year) | 0.161 | 0.168 |
| Electricity Export Revenue ($ millions/year) | 2.7 | 2.8 |
| Electricity Exported (MWh) | 7,392 | 7,457 |
| Break-Even Time (years) | 5.3 | 5.3 |
| GHG Emissions Reduced - Drought Year (tonnes/year) | 1,749.0 | 1,764.3 |
| GHG Emissions Reduced - Non-Drought Year (tonnes/year) | 349.8 | 352.9 |
| Diesel Displaced - Drought Year (Litres, millions) | 2.0 | 2.0 |
| Diesel Displaced - Non-Drought Year (Litres, millions) | 0.399 | 0.403 |

## 4.2 GROUND-UP

### 4.2.1 South Slave

Using the cost estimates described in Table 3, annual estimates for cost, energy production, GHG emissions, and fuel consumption are given in Table 6 for the Pine Point location. The estimates are generated with respect to possible plant configurations. The considered configurations align with the discussion in Section 3.3; all modules are bifacial, and are tilted vertically, or at 50°, or a mixture of both (70% vertical modules and 30% tilted modules at 50°).

**Table 6: Effects of a 5 MW Solar PV Plant on Cost, Energy, GHG, and Fuel estimates, with respect to three possible plant configurations.**

| | Vertical Bifacial | Mixed | Sloped Bifacial |
|---|---|---|---|
| Initial Cost ($, millions) | 11.00 | 11.00 | 11.00 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 | 0.19 |
| Electricity Export Revenue ($, millions/year) | 2.3 | 2.6 | 2.8 |
| Average Annual Electricity Exported (MWh) and Quantiles (5%, 95%) | 5616<br>(5320, 5878) | 6252<br>(5885, 6558) | 6889<br>(6450, 7238) |
| Break-Even Time (years) | 5.1 | 4.6 | 4.2 |
| GHG Emissions Reduced (tonnes/year) | 1,558<br>(1476, 1631) | 1,735<br>(1633,1820) | 1,911<br>(1790, 2008) |
| LNG Fuel Displaced (Litres, Millions) | 1.97 | 2.19 | 2.41 |

The ground-up approach produces the same initial costs across all three plant configurations. The average annual energy production is maximized for the south-facing 50° tilted bifacial configuration, though accounting for the year-over year variation allows for some overlap with the mixture of vertical and 50° tilted bifacial configuration. Consequently, the most GHGs are reduce and the greatest amount of diesel fuel saved for the 50° tilted bifacial configuration as well. This is not unexpected; the tilted bifacial configuration was specifically chosen to maximize annual energy production as noted in Section 3.1.4.

The intra-year energy generated by each plant configuration is given in Figure 7, plotting the average cumulative energy generated across the 20 years of NASA irradiance data.

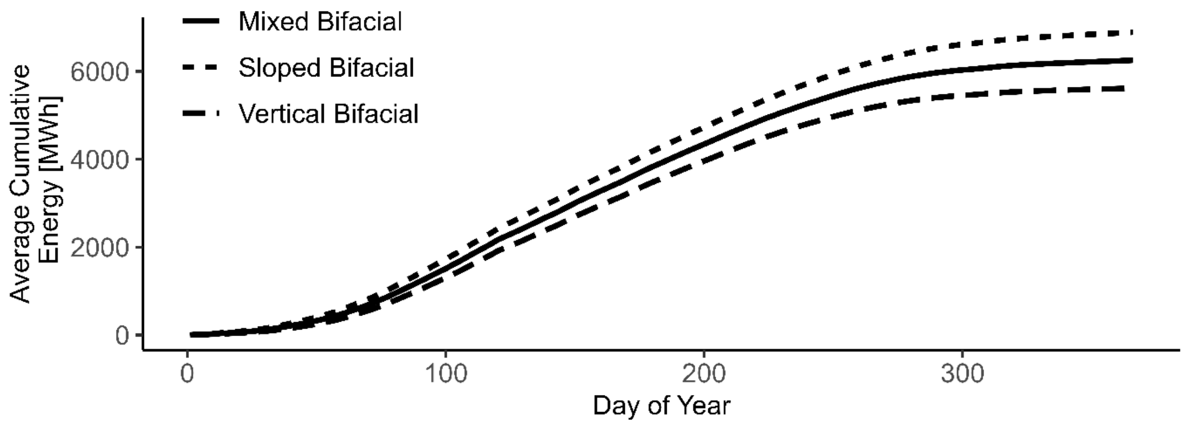


**Figure 7: Average yearly cumulative energy generated for considered solar PV plant configurations in Pine Point.**

The energy generated throughout the year follows a similar curve for all three investigated configurations, with the greatest amount of energy generated during the summer months and tapering off during the winter month. This is unsurprising given the relatively larger difference in daylight hours between the summer and winter at high latitudes.

### 4.2.2 North Slave

As with the South Slave location, annual estimates for costs, energy production, GHG emissions, and fuel consumption are given in Table 7. However, given the characteristics of utility-side energy generation in the North Slave grid, discussed in Section 3.1.3, the configurations analyzed are limited to vertical bifacial modules, and a mixture of vertical bifacial modules and modules tilted at 52° (70% vertical modules and 30% tilted modules at 50°). The goal is to study configurations which are most likely to be compatible with producing offsets in current diesel energy generation from the utility, which maximizes later in the day. To this end, the results are also analyzed with respect to drought and non-drought years, given the large difference in utility-side diesel generation between the two scenarios.

**Table 7: Effects of a 5 MW Solar PV Plant on Cost, Energy, GHG, and Fuel estimates, with respect to three possible plant configurations and drought years versus non-drought years.**

| | Vertical Bifacial | Mixed |
|---|---|---|
| Initial Cost ($, millions) | 11.00 | 11.00 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 |
| Electricity Export Revenue ($, millions/year) | 0.238 | 0.253 |
| Average Annual Electricity Exported (MWh) and Quantiles (5%, 95%) | 5805 (5524,6069) | 6182 (5883, 6463) |
| Break-Even Time (years) | 5 | 4.7 |
| GHG Emissions Reduced (tonnes/year) – Non-drought Year | 461 | 506 |
| GHG Emissions Reduced (tonnes/year) – Drought Year | 2314 | 2474 |
| Diesel Fuel Displaced (Litres, Millions) – Non-drought Year | 0.311 | 0.341 |
| Diesel Fuel Displaced (Litres, Millions) – Drought Year | 1.56 | 1.67 |

As with the South Slave Pine Point plant in Table 6, the initial costs are constant with respect to the configuration, and indeed the location, as they are the exact same in the North Slave Yellowknife location. The amount of energy generated between the two investigated configurations for Yellowknife lie within similar ranges as their Pine Point counterparts: 5805 versus 5616 average annual MWh for the vertical configuration and 6182 versus 6252 average annual MWh for the mixture of 50° tilted and vertical configuration. It is again important to note that given the need to generate a solar energy profile commensurate with the known diesel generation profile for the North Slave grid, the configuration that will give the maximum annual energy production is not considered here. The mixed configuration is likely to generate the most energy at the cheapest cost, while saving a greater amount of GHGs and diesel fuel. The amount of GHGs and diesel fuel saved are broken down by whether the underlying diesel generation profile is in a drought year or not. The potential for savings in GHGs and diesel fuel is maximized in drought years, unsurprisingly, but even in non-drought years there is potential for a solar PV plant to add value.

The intra-year energy generated by each plant configuration is given in Figure 8, plotting the average cumulative energy generated across the 20 years of NASA irradiance data.

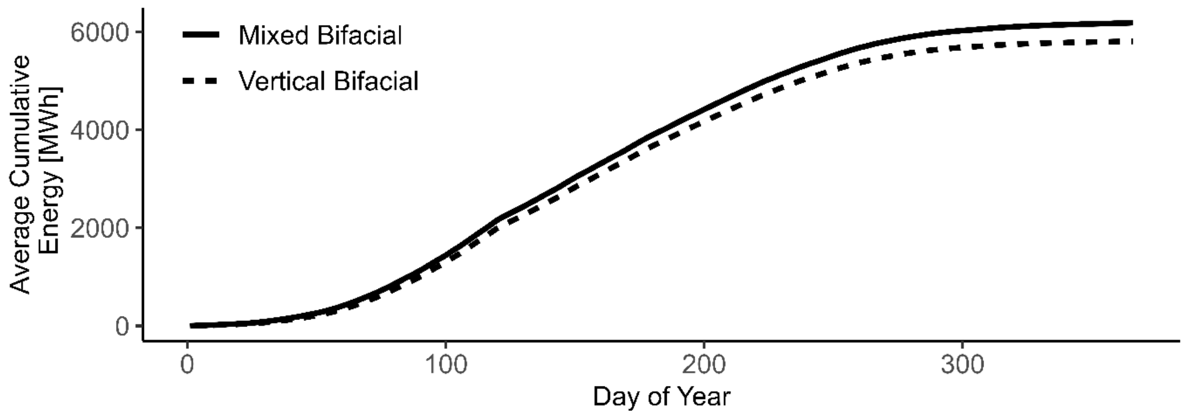


**Figure 8: Average yearly cumulative energy generated for considered solar PV plant configurations in Yellowknife.**

The energy generated throughout the year follows a similar curve for the two investigated configurations, with the same pattern as in Figure 7 showing the greatest amount of energy generated during the summer months and tapering off during the winter month.

## 4.3 DIAVIK SOLAR PLANT

Using the 0.75% degradation rate assumed in Section 3.4, the five years of wear on the Diavik solar PV plant through its current expected operation of 2024 through 2029, result in a 3.7% decrease in Diavik plant performance. The plant is rated for 3.5 MW, so the rated performance of the plant at the end of its operations in Diavik is assumed to be 3.37 MW. Thus, the Diavik mine solar plant has the potential to account for 67% of the desired 5 MW capacity. Using the NREL cost estimates for the relevant solar PV components (panels and inverters), this translates to a reduction of $2.76M 2025 Canadian dollars in installation costs. Note that the ground-up approach does not distinguish between installation costs in either the South Slave Pine Point or North Slave Yellowknife locations, the $2.76M figure is the same for both.

In Figure 9 the range of possible annual energy generation (5320 MWh to 7328 MWh, reported in Table 6 and Table 7) is plotted against the range of possible degradation values. As outlined in Section 3.4, the average year over year degradation expected by NREL is 0.75%. However, the solar modules used in the Diavik mine guarantee a degradation rate of no more than 0.45% a year after the first year of usage (the first-year degradation is guaranteed to be no more than 2 %). The range of year over year degradation values considered is thus between 0.45% and 0.75%. Figure 9 shows a contour plot, with the contours demonstrating the effect degradation rates and the annual energy production has on the savings attributable to the re-use of the Diavik equipment. Essentially, Figure 9 explores the trade-off between reduced plant performance due to using equipment with five years of wear against the cost savings of acquiring the equipment for no cost. Figure 9 was calculated using a 30-year plant life.

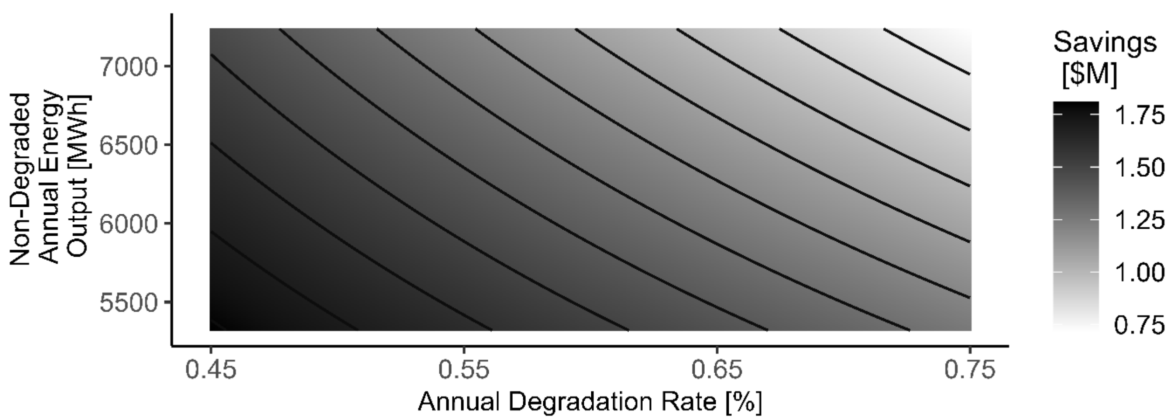


**Figure 9: Contour plot showing the effects of degradation rate and annual energy production on the trade-off between reduced plant performance and lower plant installation costs when re-using Diavik equipment.**

At all possible combinations of degradation rate and non-degraded annual energy production, the Diavik equipment results in cost savings. However, this calculation does not account for costs associated with dismantling and moving Diavik plant components. As NT Energy is better positioned to obtain accurate costing estimates with respect to the dismantling/moving of Diavik components, what this analysis shows is the range in which the use of these panels can remain viable. For example, if the total cost of repurposing the panels is $1M, then assuming annual energy production of 5500-7000 MWh and annual degradation rates of 0.45-0.55%, repurposing Diavik equipment will save between $0.75M to $0.25M over a 30-year plant lifetime.

To better assess the effects of plant-lifetime on the Diavik trade-off, the net savings for the average annual MWh of the vertical, sloped, and mixed configuration for the South Slave location, shown in Table 6, is given in Figure 10. The North Slave locations are omitted for brevity, and comparing the annual energy potentials reported in Table 7 with the values in Figure 10 is straightforward. Note this calculation assumes an average annual degradation rate of 0.6% year over year.

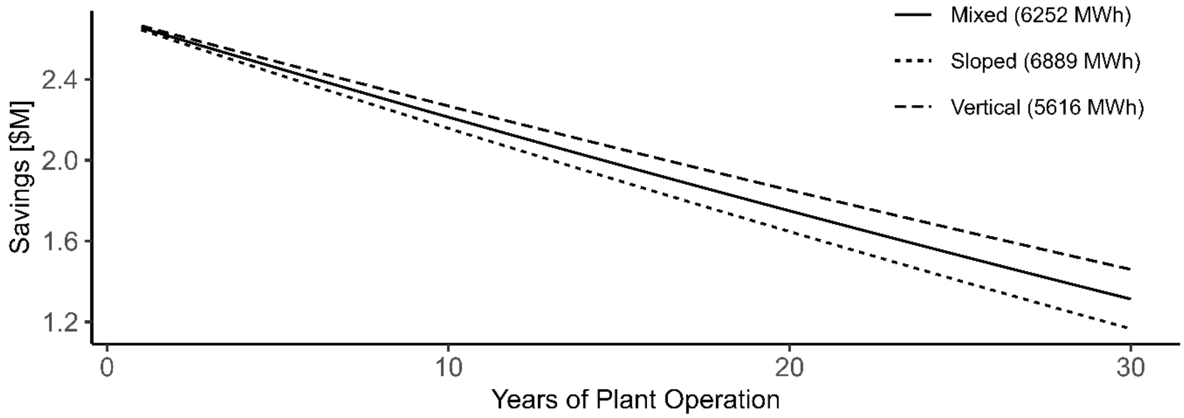


**Figure 10: Effect of length of plant operation on trade-off between reduced plant performance and lower plant installation costs when re-using Diavik equipment.**

The longer the solar plant is in operation, the greater the year-over-year degradation assumption reduces the amount of annual energy generated, and thus the value of the solar plant. For example, consider the cost of dismantling and transporting the Diavik solar components is $1M again. Then, for a solar plant in Pine Point that is decommissioned after 20 years, the Diavik components result in approximately $0.8M to $1.2M of savings (depending on annual energy generation). However, with the same conditions and a 30-year decommissioning schedule, the Diavik components result in approximately $0.2M to $0.6M in savings. In Appendix 8.6, the exact values are given that generate the plot in Figure 10, and an equivalent plot for the North Slave location.

An analysis of the effect of the Diavik panels was also completed with RETScreen. The total lifetime power generation and potential revenues of a 5 MW plant either using all new panels or including those from Diavik mine was determined, illustrated in Figure 11 and Figure 12. The accelerated degradation in the panels from Diavik slightly impact overall power and revenue generation.

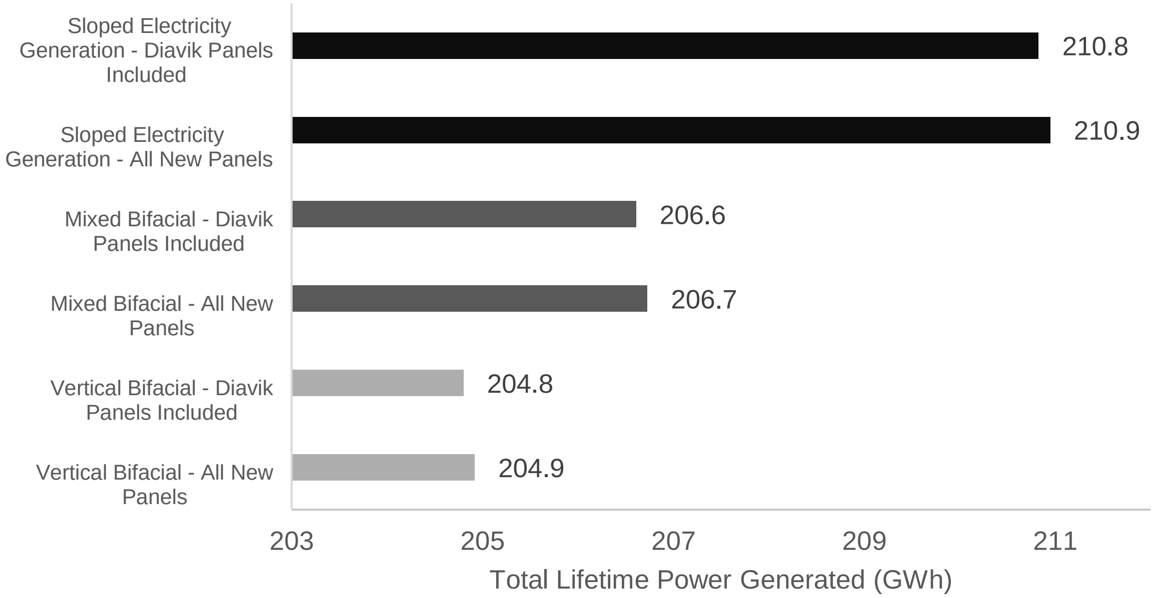


**Figure 11. Total power generation of a 5 MW plant over 30 years, depending on the incorporation of 5-year-old panels from Diavik mine. The horizontal axis has been shortened to highlight the difference between new and re-purposed panels within configurations.**

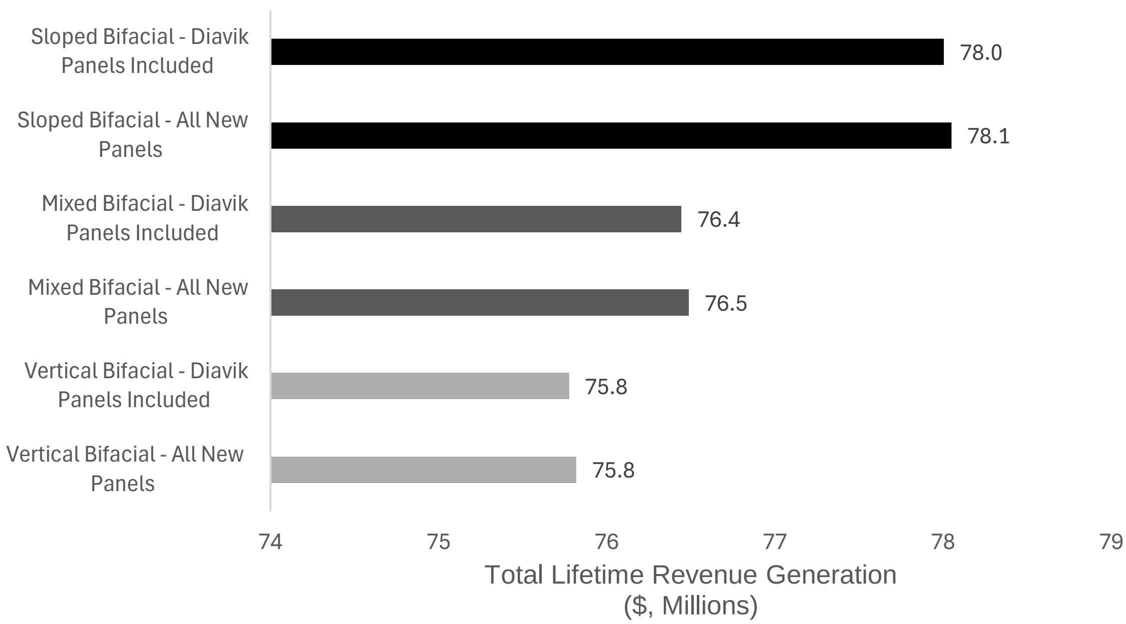


**Figure 12. Total revenue generation of a 5 MW plant over 30 years, depending on the incorporation of 5-year-old panels from Diavik mine. Values do not account for inflation. The horizontal axis has been shortened to highlight the difference between new and re-purposed panels within configurations.**

# 5 DISCUSSION

Efforts were made to keep parameters consistent between the two approaches, but there are some key differences. The ground-up approach accounted for loss of energy by transmission, placing line loss at 7.5%, whereas the RETScreen method included a 15% miscellaneous loss factor on panel generation and a 1% loss on the inverter. The RETScreen approach also assumed a very efficient bifaciality factor of 95%, whereas the ground-up approach used a more conservative 70% bifaciality factor. The RETScreen approach was able to differentiate between installation costs on the South and North Slave locations (likely as a function of latitude) whereas the ground-up approach was not and gives identical installation costs for each potential solar plant location. The ground-up approach was able to use 20 years of NASA irradiance data to calculate an average and range of likely values for annual energy production, whereas the RETScreen approach only gives a single estimate. However, both approaches evaluated the same configurations of solar modules in the same locations. In general, the RETScreen approach provided more optimistic energy production estimate, and consequently more optimistic estimates of GHG emission and fuel reductions. A more detailed summary of the results for each potential solar plant location, as well as a discussion repurposing the Diavik solar components is given below.

A rough estimate for the raw number of solar panels and inverters needed can be obtained by dividing the desired power rating of the plant of 5 MW by the power rating of solar panels and inverters. The NREL cost estimates assumed a power rating of 530 W for the considered bifacial module. The Diavik solar panels have a range of power ratings from 530 W to 555 W, which encompass the NREL assumption. Using the 530 W to 555 W range, this translates to between 9009 and 9346 solar modules. For inverters, it is not required to have the equal amounts of rated inverter capacity as there is power generation capacity. Typically, utilities maintain an imbalanced inverter load ratio to maximize the efficiency and performance of the inverter. NREL assumed an inverter load ratio of 1.34. Employing this ratio, using the same class of inverters as used in Diavik [45], results in between 27 and 35 inverters (depending on exact makeup of the inverter models). It is important to note that there is a trade-off between using many inverters with a smaller power rating, or fewer inverters with a larger power rating. The smaller inverters can be installed and maintained by professionals more easily, with less training and official certifications. Larger inverters with a higher voltage rating require more expertise to safely install and operate. However, larger inverters are more efficient and can reliably move power over greater distances with fewer losses. Ultimately the optimal inverter configuration will be dependent on the exact plant site, and other factors related to a specific technical assessment of the solar plant design.

## 5.1 SOUTH SLAVE

In Table 8, a direct comparison is given between the relevant metrics for both the RETScreen and ground-up approaches.

**Table 8. Values from both RETScreen and the Ground-Up methodology for the South Slave solar plant.**

| | RETScreen | | | Ground-Up | | |
|---|---|---|---|---|---|---|
| | Vertical Bifacial | Mixed Bifacial | Sloped Bifacial | Vertical Bifacial | Mixed Bifacial | Sloped Bifacial |
| Initial Cost ($, millions) | 13.72 | 13.72 | 13.72 | 11.00 | 11.00 | 11.00 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 | 0.19 | 0.16 | 0.17 | 0.19 |
| Electricity Export Revenue ($, millions/year) | 3.17 | 3.21 | 3.30 | 2.41 | 2.69 | 2.97 |
| Electricity Exported (MWh) | 6754 | 6836 | 7028 | 5616 | 6252 | 6889 |
| Break-Even Time (years) | 4.6 | 4.5 | 4.4 | 5.1 | 4.6 | 4.2 |
| GHG Emissions Reduced (tonnes/year) | 2305 | 2398 | 2333 | 1,558 | 1,735 | 1,911 |
| LNG Displaced (Litres, millions) | 2.36 | 2.39 | 2.46 | 1.97 | 2.19 | 2.41 |

The initial capital cost for all three RETScreen configurations is $13.72M, which considers "costs for preparing a feasibility study, performing the project development functions, completing the necessary engineering, purchasing and installing the energy (power, heating and/or cooling) equipment, implementing energy efficiency measures, construction of the balance of system and costs for any other miscellaneous items" [46]. In comparison, the ground-up approach using the NREL cost estimates predicts an installation cost of $11M. The RETScreen O&M costs vary slightly, with $161,000 per year for vertical bifacial, $168,000 per year for mixed bifacial, and $185,000 per year for sloped bifacial; the ground-up O&M costs are extremely similar. O&M cost differences between configurations are due to the decreased cleaning costs associated with vertical bifacial panels.

Among both methodologies, the sloped bifacial configuration resulted in the highest annual output, followed by mixed bifacial and then vertical bifacial. Correspondingly, the sloped bifacial configuration also achieves the highest electricity export revenue. However, the ground-up approach predicted lower annual MWh generation across all configurations than RETScreen. Differences are not consistent across configurations, though; the ground-up approach predicts approximately 1100 less MWh per year for the vertical configuration, approximately 600 less MWh per year for the mixed configuration, and approximately 200 less MWh per year for the sloped configuration. This difference is likely due to the different assumptions made between the RETScreen and ground-up approaches. The RETScreen approach assumed a 95% bifaciality factor on the rear panel; the ground-up approach assumed a 70% bifaciality factor.

The RETScreen break-even time periods are relatively consistent across system types, showing only a minor trend towards faster payback with the sloped configurations. In contrast, the ground-up method found greater variation, with nearly a one-year range between the slope and vertical payback periods. The lower installation costs associated with the ground-up approach are offset by the higher energy production estimated by the RETScreen approach.

Neither approach considers the value of the fuel displaced, but the same overall pattern is observed for the volume of LNG displaced and corresponding GHG reductions for both RETScreen and ground-up results: vertical panels displace the least amount of fuel and sloped panels displace the most. The South Slave solar plant is assumed to provide electricity that directly replaces power generation from an LNG plant, as opposed the North Slave system where solar is assumed to displace power generation from diesel sources, contingent upon the drought conditions.

Overall, the sloped bifacial system shows the highest electricity generation, quickest recoupment of installation costs when considering year over year O&M, and greatest reduction in GHG emissions. Comparing the costs estimated in Table 8 with the cost ranges reported in NT Energy's 2013 study, there are clear differences [5, p. 27]. NT Energy reported that in 2013 an energy cost estimate of between $590/MWH and $830/MWH, and an installation cost estimate of between $9000/kW and $14,000/kW. The installation costs estimated in Table 8 result in $2744/kW for the RETScreen approach, and $2200/kW for the ground-up approach. The energy costs for the RETScreen approach result in between $23/MWH and $27/MWH, whereas for the ground-up approach the energy costs range between $27/MWH and $28/MWH. The energy costs were calculated from the O&M costs. Comparing what was reported in 2013 in the NT Energy report and what is calculated in this study there is a clear reduction in costs. Due to the lack of detail around how the solar costs were determined in the NT Energy report, it is unclear if the O&M costs in Table 8 entirely capture the same information as the per MWH costs detailed in the NT Energy report. It is possible that a direct comparison is not useful for the energy costs. However, there is less ambiguity for the installation costs, and there is a clear reduction present. This aligns with Figure 3, where from 2009 through 2019 it was shown that the levelized cost of solar plants markedly decreased.

## 5.2 NORTH SLAVE

As before, in Table 9 a direct comparison is provided between the RETScreen and ground-up approaches.

**Table 9. Values from both RETScreen and the Ground-Up methodology for the North Slave solar plant.**

| | RETScreen | | Ground-Up | |
|---|---|---|---|---|
| | Vertical Bifacial | Mixed Bifacial | Vertical Bifacial | Mixed Bifacial |
| Initial Cost ($, millions) | 13.72 | 13.72 | 11.00 | 11.00 |
| Operation and Maintenance ($, millions/year) | 0.16 | 0.17 | 0.16 | 0.17 |
| Electricity Export Revenue ($, millions/year) | 2.7 | 2.8 | 2.38 | 2.53 |
| Electricity Exported (MWh) | 7392 | 7457 | 5805 | 6182 |
| Break-Even Time (years) | 5.3 | 5.3 | 5.0 | 4.7 |
| GHG Emissions Reduced - Drought Year (tonnes/year) | 1749 | 1764.3 | 2314 | 2474 |
| GHG Emissions Reduced - Non-Drought Year (tonnes/year) | 349.8 | 352.86 | 461 | 506 |
| Diesel Displaced - Drought Year (Litres, millions) | 1.996 | 2.013 | 1.560 | 1.670 |
| Diesel Displaced - Non-Drought Year (Litres, millions) | 0.399 | 0.403 | 0.311 | 0.341 |

Both the vertical and mixed configurations have an initial cost of $13.72M from RETScreen, while the ground-up approach estimates an $11M initial cost for each. The O&M costs for the vertical bifacial configuration are $161,000 per year and $168,000 per year for the mixed bifacial, and the O&M costs for the ground-up approach reached similar values. Differences in O&M costs across the configurations can be attributed to the increased cost of snow removal required by sloped panels.

With respect to electricity generation, the RETscreen approach estimates that the mixed bifacial configuration produces a marginally higher annual output. As with the South Slave location, the ground-up approach produces more conservative estimates; 5805 MWh generated annually for the vertical configuration and 6182 MWh generated annually for the mixed configuration. The additional generation associated with the mixed configuration leads to a corresponding increase in revenue: $2.7M for the vertical bifacial versus $2.8M for the mixed bifacial for the RETScreen results, whereas for the ground-up approach $2.38M is estimated to be exported with the vertical configuration and $2.53M for the mixed configuration. The payback periods are similar across configurations and analysis approach, being between 4.7 and 5.3 years.

Modelling done for the ground-up approach to determine the potential of the different panel configurations to offset diesel power generation found that 20% of power produced by the solar plant during a non-drought year ended up offsetting power from the Jackfish diesel plant, while 100% of the power went to offsetting diesel in a drought year. As a result, during a drought year, both configurations ended up offsetting around 2 million litres of diesel fuel, with RETScreen estimates showing an extra 17,000 litres offset by the mixed configuration, and the ground-up finding a 10,000-litre difference.

The mixed bifacial configuration shows the greatest potential to offset diesel and maximize energy generation. Once again, when comparing the costs estimated in Table 9 with the cost ranges reported in NT Energy's 2013 study [5, p. 27], there are reductions. The installation costs do not change between the North and South Slave locations, and are the same. The energy costs for the RETScreen approach result in between $21/MWH and $23/MWH, whereas for the ground-up approach the energy costs range between $27/MWH and $28/MWH. Overall, the comparison with the estimates in the NT Energy report for the North Slave location is almost identical to South Slave location.

## 5.3 DIAVIK SOLAR PLANT

A reasonable estimate for the wear on the solar modules and inverters used in the Diavik plant was calculated based on well-supported NREL estimates. Using the same NREL solar plant cost estimates that informed the ground-up approach, the cost savings from using the Diavik solar components in the installation of a plant on the South or North Slave locations was able to be estimated. This installation cost estimate was then compared against the decreased energy production, and associated revenue, from incorporating 67% of the proposed 5 MW plant's rated power with components with five years of wear on them. It was found that depending on the assumed degradation rate on plant components, the annual energy production of the plant, and the total amount of years the plant remained in operation, implementing solar components from the Diavik solar installation would save approximately anywhere between \$0.4M and \$2M over the plant's lifetime (assuming a 20–30-year operational period). It is crucial to note that these results are ***not*** including the costs to dismantle and transport the Diavik solar components. These results give a range of values with which to subtract the dismantling and transportation costs, which will then provide complete context for how viable the repurposing of the Diavik components will be.

Using a yearly degradation rate of 0.75%, the impact on power generation capacity of the 5-year-old Diavik panels was analyzed using RETScreen. At the end of a 30-year period, a plant that incorporated the Diavik mine panels experienced an additional drop of 3 – 4 kW in power capacity than a plant using all new panels. As seen in Figure 11 and Figure 12, the effect of the Diavik panels over a 30-year lifetime on power generation capacity and revenue is minor, assuming that all panels have a constant rate of degradation. In all panel configurations, the difference in lifetime electricity generation and revenue is less than 1% when including the Diavik panels.

# 6 CONCLUSION

This report calculated and presented important annual results for energy production, fuel savings, and GHG reductions for the proposed South Slave and North Slave solar PV plants. A literature review was conducted to support the reasoning behind the solar plant configurations used to produce these annual results for the South and North Slave locations. Two sets of results were given, one produced with the well-established RETScreen software, and another produced with a "ground-up" approach, largely informed by a well-known model for calculating solar irradiance on tilted surfaces and NREL solar industry estimates. As well, an analysis was conducted to consider the effect of repurposing components from the Diavik Diamond Mine's solar plant, both for the initial cost and operational lifetime of a utility-scale solar PV plant in the NWT.

The conclusions of this report can be largely characterized as positive. Given the factors currently at play in the NWT, including droughts increasing diesel usage, increased electric power demands on the South Slave due to a new mine opening, the declining cost of bifacial solar modules and their greater performance in higher snowy latitudes, and the availability of solar components from the Diavik Mine to be repurposed, there exists an opportunity for utility-scale solar in the NWT. The numerical results reported in this study largely indicate that utility-scale solar is feasible.

However, caution must be taken as the numerical results are estimates only. The cost estimates reported in this study are valuable as a high-level assessment, but are no substitute for detailed costings provide by a contractor with experience in renewable energy projects in the Canadian north. Further, a detailed technical study of the effect of a given solar plant configuration on the grid stability and harmonics on either the North or South Slave regional grids is necessary to fully determine the costs associated with utility-scale solar in the NWT. The energy production modeling used in this study is sufficient for calculating aggregated yearly energy production, but to fully capture the impact of a solar plant on the North or South Slave grids simulations at a high-temporal resolution with a detailed technical model of a plant configuration are needed.

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# 8 APPENDIX

## 8.1 DETAILED COST ESTIMATES FOR 5 MW SOLAR PV PLANT

The following table describes all sub-component cost elements that comprise the overall cost estimates provide by NREL, and reported on in Table 3.

**Table 10: Detailed cost estimates for each cost element component costs for solar PV plant.**

| Component Cost | Cost Element | Cost Unit | Cost per unit (2025 CAD $) | Cost for 5 MW Vertical Bifacial Solar PV Plant (2025 CAD $) |
|---|---|---|---|---|
| Module | Cells | Price Element per kWdc | 342.43 | 1,712,147 |
| Module | Frame | Price Element per kWdc | 40.30 | 201,487 |
| Module | Junction Box | Price Element per kWdc | 12.57 | 62,850 |
| Module | Other Material | Price Element per kWdc | 85.86 | 429,305 |
| Module | Labor | Price Element per kWdc | 3.84 | 19,224 |
| Module | Electricity | Price Element per kWdc | 4.00 | 19,994 |
| Module | Depreciation | Price Element per kWdc | 10.97 | 54,863 |
| Module | Maintenance | Price Element per kWdc | 1.71 | 8,536 |
| Module | Profit | Price Element per kWdc | 158.62 | 793,080 |

| | | | | |
|---|---|---|---|---|
| Module | Shipping | Price Element per kWdc | 63.68 | 318,393 |
| Inverter | Power Devices | Price Element per kWac | 41.55 | 155,039 |
| Inverter | Rest of Inverter | Price Element per kWac | 22.66 | 84,566 |
| Inverter | Packaging | Price Element per kWac | 13.22 | 49,331 |
| Inverter | Labor | Price Element per kWac | 5.93 | 22,133 |
| Inverter | Electricity | Price Element per kWac | 1.26 | 4,693 |
| Inverter | Depreciation | Price Element per kWac | 1.32 | 4,933 |
| Inverter | Maintenance | Price Element per kWac | 0.19 | 705 |
| Inverter | Profit | Price Element per kWac | 36.91 | 137,742 |
| Inverter | Shipping | Price Element per kWac | 3.21 | 11,988 |
| SBOS | Torque Tubes | Price Element per m2 | 20.40 | 494,512 |
| SBOS | Driven Piers | Price Element per m2 | 6.36 | 154,263 |
| SBOS | Module Rails | Price Element per m2 | 4.18 | 101,300 |
| SBOS | Fasteners | Price Element per m2 | 0.85 | 20,605 |

| | | | | |
|---|---|---|---|---|
| SBOS | Dampers | Price Element per m2 | 0.93 | 22,497 |
| SBOS | Control Electronics | Price Element per m2 | 1.81 | 43,825 |
| SBOS | Shipping | Price Element per m2 | 5.67 | 137,355 |
| EBOS | Transformers | Price Element per kWac | 75.54 | 281,884 |
| EBOS | Switches | Price Element per kWac | 23.60 | 88,073 |
| EBOS | Breakers | Price Element per kWac | 47.20 | 176,146 |
| EBOS | Conductors | Price Element per kWac | 30.20 | 112,677 |
| EBOS | Combiner Boxes | Price Element per kWac | 23.60 | 88,073 |
| EBOS | Grounding | Price Element per kWac | 22.66 | 84,565 |
| EBOS | Substation | Price Element per kWac | 82.64 | 308,357 |
| EBOS | Transmission | Price Element per kWac | 38.30 | 142,910 |
| EBOS | Network Upgrade | Price Element per kWac | 113.21 | 422,441 |
| EBOS | Shipping | Price Element per kWac | 1.13 | 4,228 |
| Fieldwork | EBOS Labor | Price Element per m2 | 19.08 | 462,667 |

| | | | | |
|---|---|---|---|---|
| Fieldwork | SBOS Labor | Price Element per m2 | 25.72 | 623,636 |
| Fieldwork | Labor Burden | Price Element per m2 | 24.19 | 586,603 |
| Fieldwork | Site Prep | Price Element per m2 | 0.47 | 11,449 |
| Fieldwork | Equipment Rental | Price Element per m2 | 20.96 | 508,252 |
| Fieldwork | Inspection | Price Element per m2 | 3.78 | 91,575 |
| Officework | Warehousing | Price Element per kWdc | 12.90 | 64,488 |
| Officework | Logistics | Price Element per kWdc | 9.95 | 49,744 |
| Officework | Engineering | Price Element per kWdc | 30.00 | 149,991 |
| Officework | Permits | Price Element per kWdc | 3.97 | 19,830 |
| Officework | Interconnect | Price Element per kWdc | 58.74 | 293,714 |
| Officework | Outreach | Price Element per kWdc | 12.99 | 64,950 |
| Other | Sales Tax | Price Element per kWdc | 81.72 | 408,609 |
| Other | Contingency | Price Element per kWdc | 29.96 | 149,783 |
| Other | Management | Price Element per kWdc | 40.34 | 201,719 |

| | | | | |
|---|---|---|---|---|
| Other | Profit | Price Element per kWdc | 108.01 | 540,051 |
| Operations and Maintenance | Cleaning | Price Element per kWdc-yr | 4.84 | 24,192 |
| Operations and Maintenance | Inspection | Price Element per kWdc-yr | 2.94 | 14,705 |
| Operations and Maintenance | New BOS | Price Element per kWdc-yr | 2.45 | 12,245 |
| Operations and Maintenance | New Modules | Price Element per kWdc-yr | 0.49 | 2,462 |
| Operations and Maintenance | New Inverters | Price Element per kWdc-yr | 4.57 | 22,859 |
| Operations and Maintenance | Land Lease | Price Element per kWdc-yr | 4.07 | 20,360 |
| Operations and Maintenance | Property Tax | Price Element per kWdc-yr | 3.79 | 18,930 |
| Operations and Maintenance | Insurance | Price Element per kWdc-yr | 5.64 | 28,214 |
| Operations and Maintenance | Management | Price Element per kWdc-yr | 3.45 | 17,272 |

## 8.2 SIMULATION RESULTS TO DETERMINE OPTIMAL PANEL TILTS FOR SOUTH AND NORTH SLAVE LOCATIONS

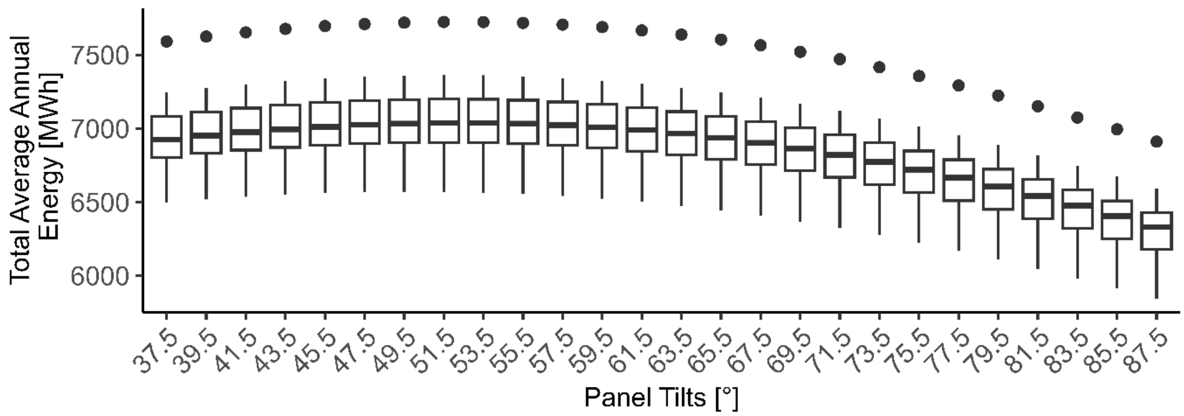


**Figure 13: Simulation results for Yellowknife optimal panel tilts with respect to average annual energy production and a 5 MW bifacial solar PV plant. Calculated with isotropic diffuse model.**

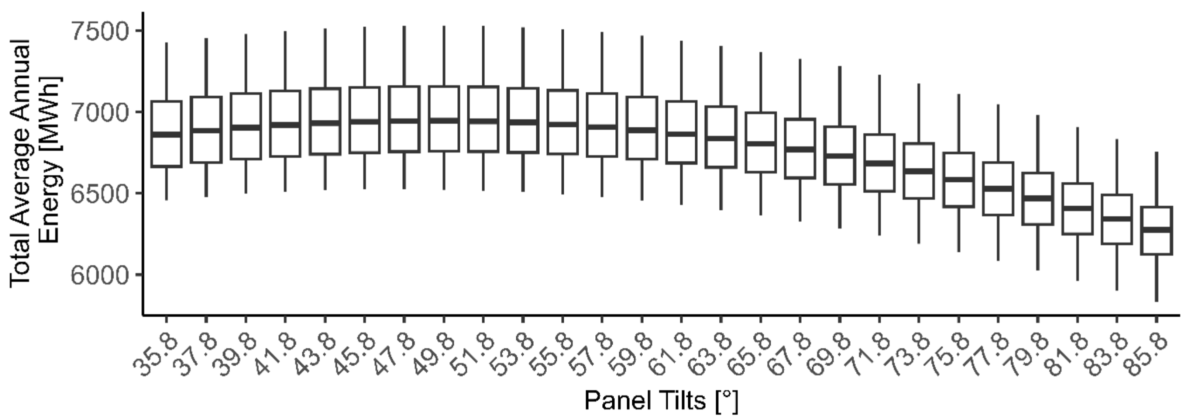


**Figure 14: Simulation results for Pine Point optimal panel tilts with respect to average annual energy production and a 5 MW bifacial solar PV plant. Calculated with isotropic diffuse model.**

## 8.3 TECHNICAL DETAILS FOR THE ISOTROPIC DIFFUSE MODEL

The energy potential on a tilted surface can be modeled using an isotropic diffuse model [47, p. 91]. RETScreen uses this approach, though they note that while it is not the most accurate model available, it is suitable for a “pre-feasibility stage” [48, p. 191]. The isotropic diffuse model is widely used and simple, however it’s estimates for solar energy potential on tilted surfaces are generally conservative [47, p. 98]. Going forward the isotropic diffuse model will be employed though more complex models may be investigated in the future. The isotropic diffuse model is useful because it describes the energy potential on the tilted surface as a function of the Global Horizontal Irradiance (GHI), as well as the diffuse and beam components of solar irradiance. NASA provides both GHI and diffuse irradiance data through their POWER web portal for any location on earth at an hourly resolution. Using established formulae to calculate solar time, hour angle, azimuth, zenith, and incidence angle to the surface, in conjunction with the NASA provided GHI and diffuse irradiance data is sufficient to calculate the isotropic diffuse model.

The isotropic diffuse model is described in (1).

$$I_T = I_b R_b + I_d\left(\frac{1+\cos\beta}{2}\right) + I\rho\left(\frac{1-\cos\beta}{2}\right) \tag{1}$$

Where $I_t$ is the total irradiance on the tilted surface, $I_b$ is the beam component of the irradiance, $R_b$ is the ratio of the beam radiation on the tilted surface to the beam radiation on the horizontal, $I_d$ is the diffuse component of the irradiance, $I$ is the GHI, $\beta$ is the slope of the tilted surface, and $\rho$ is the diffuse reflectance of the ground (also known as the ground albedo).

A simple rule of thumb is employed for the ground albedo; when the average monthly temperature $T$ is greater than $0$°C then $\rho = 0.2$, when $T$ is less than $-5$°C then $\rho = 0.7$, all values between these two conditions are linearly interpolated [48, p. 191].

In (1) the second and third terms can be calculated from the available NASA data for GHI and diffuse irradiance, as well as assumed values for the solar panel slope and the ground albedo. The beam irradiance $I_b$ is simple to calculate given that $I$ and $I_d$ are known, and is shown in (2).

$$I_b = I - I_d \tag{2}$$

The ratio $R_b$ is calculated by equation (3).

$$R_b = \frac{\cos i}{\cos\theta_z} \tag{3}$$

Where $i$ is the angle of incidence described and $\theta_z$ is the zenith angle of the sun. When $i$ is greater than 90° it corresponds to the sun’s rays hitting behind the surface of the panel, and the cosine return a negative. A negative $R_b$ value in the context of equation (1) is nonsensical, so $R_b$ is only evaluated for $0 \leq i \leq \frac{\pi}{2}$ and $I_b$ is assumed to be 0 outside of this range. For more details on the isotropic diffuse model see [47, pp. 91-92].

A problem with the evaluation of equation (3) occurs when $\theta_z$ is close to 90°. The cosine returns values infinitely close to 0 as the input to the function approaches $\frac{\pi}{2}$. This means when the sun is close to the horizon values of $R_b$ can become very large, resulting in incorrect outputs for the isotropic diffuse model. To rectify this, NASA recommends using a linear component to evaluate the hourly $\cos\theta_z$ when the solar zenith exceeds 75° [49]. The details are given in (4), where $\mu$ stands for $\cos\theta_z$ and $\mu_{eff}$ is the effective $\cos\theta_z$.

$$\mu_{eff} = \begin{cases} \mu, & \theta_z \leq 75^\circ \\ \mu + \left(\frac{-k}{\cos 75^\circ}\mu + k\right), & x > 75^\circ \end{cases} \tag{4}$$

Where $k$ is an adjustable parameter. NASA reports than when $k = 0.045$ the bias between the effective hourly solar zenith angle and the true zenith angle are minimized, and thus this parametrization is what is used going forward.

The detailed steps for using the isotropic diffuse model with the NASA POWER diffuse irradiance and GHI data is given below in Figure 15.

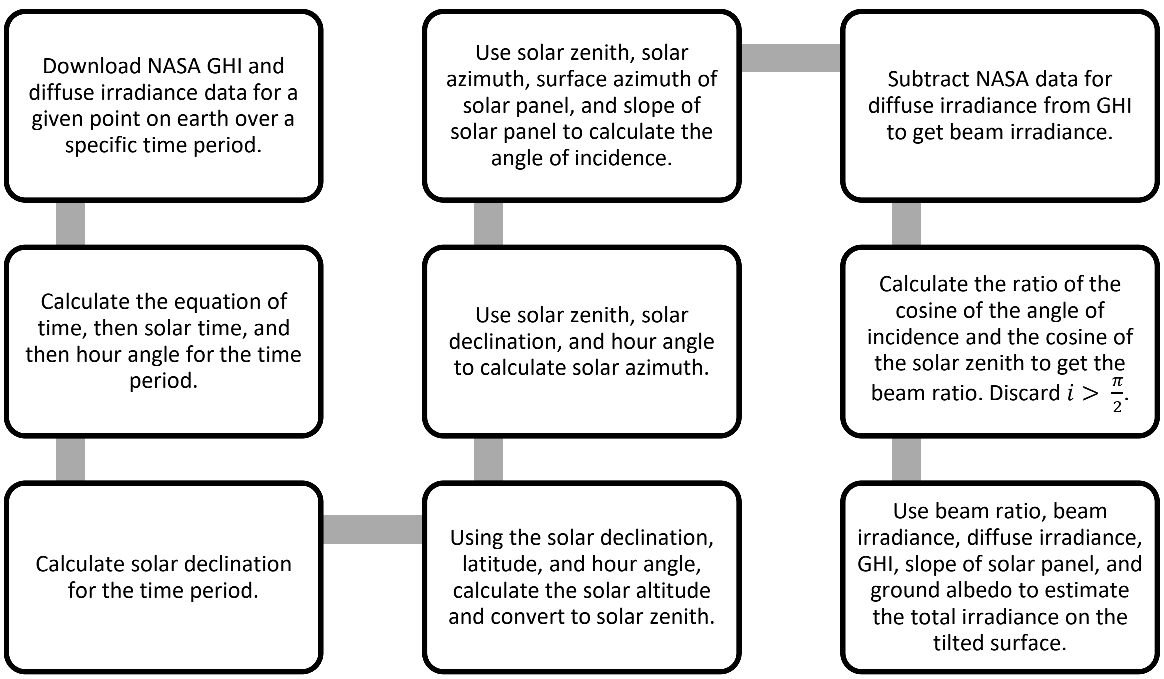


**Figure 15: Detailed workflow for calculating the energy potential on a tilted surface for a given location on earth, using NASA POWER data.**

## 8.4 RETScreen Parameters for South and North Slave

**Table 11: Parameters input into RETScreen for the South Slave evaluation.**

| Scenario Label | Vertical Bifacial | Sloped Bifacial | Mixed |
|---|---|---|---|
| Location | South Slave | South Slave | South Slave |
| Drought Condition | 1 | 1 | 1 |
| Azimuth | 90 | 0 | NA |
| Power Capacity (kW) | 5000 | 5000 | 5000 |
| Solar Panel Type | mono-Si | mono-Si | mono-Si |
| Solar Tracking Mode | Fixed | Fixed | Fixed |
| Solar Panel Slope | 90 | 50 | 50 |
| Northern Adjustment Factor | 1.28 | 1.28 | 1.28 |
| Cumulative Inflation | 7% | 7% | 7% |
| Bifacial Cell Adjustment Factor | 95% | 21% | 73% |
| Solar Panel Efficiency | 20.50% | 20.50% | 20.50% |
| Miscellaneous Losses | 15% | 15% | 15% |
| Inverter Efficiency | 96% | 96% | 96% |
| Inverter Capacity (kW) | 4,000 | 4,000 | 4,000 |
| Inverter Losses | 1% | 1% | 1% |
| Electricity Export Rate ($/kWh) | $0.47 | $0.47 | $0.47 |
| GHG Produced by Diesel (tCO2/MWh) | 0.367 | 0.367 | 0.367 |
| T&D Losses | 5% | 5% | 5% |
| Bifacial Cost Factor | 1.0741 | 1.0741 | 1.0741 |

**Table 12: Parameters input into RETScreen for the North Slave evaluation.**

| Scenario Label | Vertical Bifacial | Vertical Bifacial | Sloped Bifacial | Sloped Bifacial | Mixed | Mixed |
|---|---|---|---|---|---|---|
| Location | North Slave | North Slave | North Slave | North Slave | North Slave | North Slave |
| Drought Condition | 1 | 0.2 | 1 | 0.2 | 1 | 0.2 |
| Azimuth | 90 | 90 | 0 | 0 | NA | NA |
| Power Capacity (kW) | 5000 | 5000 | 5000 | 5000 | 5000 | 5000 |
| Solar Panel Type | mono-Si | mono-Si | mono-Si | mono-Si | mono-Si | mono-Si |
| Solar Tracking Mode | Fixed | Fixed | Fixed | Fixed | Fixed | Fixed |
| Solar Panel Slope | 90 | 90 | 52 | 52 | 52 | 52 |
| Northern Adjustment Factor | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 |
| Cumulative Inflation | 7% | 7% | 7% | 7% | 7% | 7% |
| Bifacial Cell Adjustment Factor | 95% | 95% | 21% | 21% | 73% | 73% |
| Solar Panel Efficiency | 20.50% | 20.50% | 20.50% | 20.50% | 20.50% | 20.50% |
| Miscellaneous Losses | 15% | 15% | 15% | 15% | 15% | 15% |
| Inverter Efficiency | 96% | 96% | 96% | 96% | 96% | 96% |
| Inverter Capacity (kW) | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 |
| Inverter Losses | 1% | 1% | 1% | 1% | 1% | 1% |
| Electricity Export Rate ($/kWh) | $0.37 | $0.37 | $0.37 | $0.37 | $0.37 | $0.37 |
| GHG Produced by Diesel (tCO2/MWh) | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |

| | | | | | | |
|---|---|---|---|---|---|---|
| T&D Losses | 5% | 5% | 5% | 5% | 5% | 5% |
| Bifacial Cost Factor | 1.0741 | 1.0741 | 1.0741 | 1.0741 | 1.0741 | 1.0741 |

## 8.5 RETScreen Equations

To calculate values either from the RETScreen outputs or to calculate inputs for RETScreen, the following equations were used.

The amount of fuel displaced by the configuration was calculated as the amount of electricity produced by the solar array multiplied by the litres of fuel needed to produce that same amount of electricity. The presence of a drought year made the solar electricity to fuel replacement ratio 1:1, while a non-drought year was a 1:0.2 ratio.

$$\begin{aligned}&\boldsymbol{Fuel\ Displaced}\\&= \boldsymbol{Electricity\ Exported} \times \boldsymbol{L/kWh\ of\ Fuel} \times \boldsymbol{Drought\ Condition}\end{aligned} \qquad 5$$

The operational and maintenance (O&M) costs for vertical and sloped configurations was calculated by taking the RETScreen output and applying the northern adjustment factor of 28%. The sloped configurations had an additional $4.84 per kW applied to reflect the increased snow clearing that would be required. This additional cost was calculated as part of the ground-up approach.

$$\boldsymbol{Vertical\ Panel\ O\&M\ Cost} = \boldsymbol{O\&M\ Cost} \times \boldsymbol{Northern\ Adjustment\ Factor} \qquad 6$$

$$\begin{aligned}&\boldsymbol{Sloped\ Panel\ O\&M\ Cost}\\&= \boldsymbol{O\&M\ Cost} \times \boldsymbol{Northern\ Adjustment\ Factor} + (\mathbf{4.84} \times \boldsymbol{Plant\ Size})\end{aligned} \qquad 7$$

The total initial cost of the configuration was the initial cost from RETScreen multiplied by the northern adjustment factor and the additional cost of bifacial panels compared to monofacial. RETScreen does not provide a method for reflecting the increased cost of bifacial panels, so the 7.41% cost increase determined in the ground-up approach was used.

$$\begin{aligned}&\boldsymbol{Total\ Initial\ Cost}\\&= \boldsymbol{Initial\ Cost} \times \boldsymbol{Northern\ Adjustment\ Factor}\\&\times \boldsymbol{Bifacial\ Cost\ Factor}\end{aligned} \qquad 8$$

The break-even time for the configuration was calculated as the total initial cost divided by the annual revenue gained by the sale of the generated electricity with the annual O&M costs subtracted.

$$\begin{aligned}&\boldsymbol{Break - Even\ Time}\\&= \boldsymbol{Total\ Initial\ Cost} \div (\boldsymbol{Export\ Revenue} - \boldsymbol{O\&M\ Cost})\end{aligned} \qquad 9$$

Total GHG emissions reduction was calculated as the GHG emissions reduced output from RETScreen multiplied by the drought condition.

$$\begin{aligned}&\boldsymbol{Total\ GHG\ Emissions\ Reduced}\\&= \boldsymbol{GHG\ Emissions\ Reduced} \times \boldsymbol{Drought\ Condition}\end{aligned} \qquad 10$$

RETScreen can only analyze one panel configuration at a time—either all vertical bifacial panels or all sloped bifacial panels. To determine the values for a mixed system that includes both vertical and sloped bifacial panels, the metrics were first calculated for an all-vertical configuration and an all-sloped configuration in RETScreen. The values for a mixed configuration were computed using a weighted addition, where the contribution from each configuration was multiplied by the respective panel ratio before being summed to obtain the mixed configuration value.

$$\boldsymbol{Mixed\ Configuration\ Value} = (\mathbf{0.7} \times \boldsymbol{Bifacial\ Value}) + (\mathbf{0.3} \times \boldsymbol{Sloped\ Value}) \quad (11)$$

## 8.6 TABULAR VALUES FOR SAVINGS USING DIAVIK COMPONENTS OVER 30 YEARS

**Table 13: Year-over-year savings from employing Diavik solar equipment in the South Slave Pine Point Location. Assumes a year over year degradation value of 0.6%.**

| Year | Configuration | Savings ($M) |
|---|---|---|
| 1 | Vertical (5616 MWh) | 2.67 |
| 1 | Mixed (6252 MWh) | 2.66 |
| 1 | Sloped (6889 MWh) | 2.64 |
| 2 | Vertical (5616 MWh) | 2.62 |
| 2 | Mixed (6252 MWh) | 2.6 |
| 2 | Sloped (6889 MWh) | 2.59 |
| 3 | Vertical (5616 MWh) | 2.58 |
| 3 | Mixed (6252 MWh) | 2.55 |
| 3 | Sloped (6889 MWh) | 2.53 |
| 4 | Vertical (5616 MWh) | 2.53 |
| 4 | Mixed (6252 MWh) | 2.51 |
| 4 | Sloped (6889 MWh) | 2.48 |
| 5 | Vertical (5616 MWh) | 2.49 |
| 5 | Mixed (6252 MWh) | 2.46 |
| 5 | Sloped (6889 MWh) | 2.43 |
| 6 | Vertical (5616 MWh) | 2.44 |
| 6 | Mixed (6252 MWh) | 2.41 |
| 6 | Sloped (6889 MWh) | 2.37 |

| | | |
|---|---|---|
| 7 | Vertical (5616 MWh) | 2.4 |
| 7 | Mixed (6252 MWh) | 2.36 |
| 7 | Sloped (6889 MWh) | 2.32 |
| 8 | Vertical (5616 MWh) | 2.35 |
| 8 | Mixed (6252 MWh) | 2.31 |
| 8 | Sloped (6889 MWh) | 2.26 |
| 9 | Vertical (5616 MWh) | 2.31 |
| 9 | Mixed (6252 MWh) | 2.26 |
| 9 | Sloped (6889 MWh) | 2.21 |
| 10 | Vertical (5616 MWh) | 2.27 |
| 10 | Mixed (6252 MWh) | 2.21 |
| 10 | Sloped (6889 MWh) | 2.16 |
| 11 | Vertical (5616 MWh) | 2.23 |
| 11 | Mixed (6252 MWh) | 2.17 |
| 11 | Sloped (6889 MWh) | 2.11 |
| 12 | Vertical (5616 MWh) | 2.18 |
| 12 | Mixed (6252 MWh) | 2.12 |
| 12 | Sloped (6889 MWh) | 2.05 |
| 13 | Vertical (5616 MWh) | 2.14 |
| 13 | Mixed (6252 MWh) | 2.07 |
| 13 | Sloped (6889 MWh) | 2 |
| 14 | Vertical (5616 MWh) | 2.1 |

| | | |
|---|---|---|
| 14 | Mixed (6252 MWh) | 2.02 |
| 14 | Sloped (6889 MWh) | 1.95 |
| 15 | Vertical (5616 MWh) | 2.06 |
| 15 | Mixed (6252 MWh) | 1.98 |
| 15 | Sloped (6889 MWh) | 1.9 |
| 16 | Vertical (5616 MWh) | 2.02 |
| 16 | Mixed (6252 MWh) | 1.93 |
| 16 | Sloped (6889 MWh) | 1.85 |
| 17 | Vertical (5616 MWh) | 1.97 |
| 17 | Mixed (6252 MWh) | 1.89 |
| 17 | Sloped (6889 MWh) | 1.8 |
| 18 | Vertical (5616 MWh) | 1.93 |
| 18 | Mixed (6252 MWh) | 1.84 |
| 18 | Sloped (6889 MWh) | 1.75 |
| 19 | Vertical (5616 MWh) | 1.89 |
| 19 | Mixed (6252 MWh) | 1.79 |
| 19 | Sloped (6889 MWh) | 1.7 |
| 20 | Vertical (5616 MWh) | 1.85 |
| 20 | Mixed (6252 MWh) | 1.75 |
| 20 | Sloped (6889 MWh) | 1.65 |
| 21 | Vertical (5616 MWh) | 1.81 |
| 21 | Mixed (6252 MWh) | 1.7 |

| | | |
|---|---|---|
| 21 | Sloped (6889 MWh) | 1.6 |
| 22 | Vertical (5616 MWh) | 1.77 |
| 22 | Mixed (6252 MWh) | 1.66 |
| 22 | Sloped (6889 MWh) | 1.55 |
| 23 | Vertical (5616 MWh) | 1.73 |
| 23 | Mixed (6252 MWh) | 1.62 |
| 23 | Sloped (6889 MWh) | 1.5 |
| 24 | Vertical (5616 MWh) | 1.69 |
| 24 | Mixed (6252 MWh) | 1.57 |
| 24 | Sloped (6889 MWh) | 1.45 |
| 25 | Vertical (5616 MWh) | 1.65 |
| 25 | Mixed (6252 MWh) | 1.53 |
| 25 | Sloped (6889 MWh) | 1.4 |
| 26 | Vertical (5616 MWh) | 1.61 |
| 26 | Mixed (6252 MWh) | 1.48 |
| 26 | Sloped (6889 MWh) | 1.35 |
| 27 | Vertical (5616 MWh) | 1.57 |
| 27 | Mixed (6252 MWh) | 1.44 |
| 27 | Sloped (6889 MWh) | 1.31 |
| 28 | Vertical (5616 MWh) | 1.54 |
| 28 | Mixed (6252 MWh) | 1.4 |
| 28 | Sloped (6889 MWh) | 1.26 |

| | | |
|---|---|---|
| 29 | Vertical (5616 MWh) | 1.5 |
| 29 | Mixed (6252 MWh) | 1.36 |
| 29 | Sloped (6889 MWh) | 1.21 |
| 30 | Vertical (5616 MWh) | 1.46 |
| 30 | Mixed (6252 MWh) | 1.31 |
| 30 | Sloped (6889 MWh) | 1.17 |

**Table 14: Year-over-year savings from employing Diavik solar equipment in the North Slave Yellowknife Location. Assumes a year over year degradation value of 0.6%.**

| Year | Configuration | Savings ($M) |
|---|---|---|
| 1 | Vertical (5805 MWh) | 2.66 |
| 1 | Mixed (6182 MWh) | 2.66 |
| 2 | Vertical (5805 MWh) | 2.62 |
| 2 | Mixed (6182 MWh) | 2.61 |
| 3 | Vertical (5805 MWh) | 2.57 |
| 3 | Mixed (6182 MWh) | 2.56 |
| 4 | Vertical (5805 MWh) | 2.52 |
| 4 | Mixed (6182 MWh) | 2.51 |
| 5 | Vertical (5805 MWh) | 2.48 |
| 5 | Mixed (6182 MWh) | 2.46 |
| 6 | Vertical (5805 MWh) | 2.43 |
| 6 | Mixed (6182 MWh) | 2.41 |
| 7 | Vertical (5805 MWh) | 2.39 |
| 7 | Mixed (6182 MWh) | 2.36 |
| 8 | Vertical (5805 MWh) | 2.34 |
| 8 | Mixed (6182 MWh) | 2.31 |
| 9 | Vertical (5805 MWh) | 2.3 |
| 9 | Mixed (6182 MWh) | 2.27 |
| 10 | Vertical (5805 MWh) | 2.25 |
| 10 | Mixed (6182 MWh) | 2.22 |

| | | |
|---|---|---|
| 11 | Vertical (5805 MWh) | 2.21 |
| 11 | Mixed (6182 MWh) | 2.17 |
| 12 | Vertical (5805 MWh) | 2.16 |
| 12 | Mixed (6182 MWh) | 2.13 |
| 13 | Vertical (5805 MWh) | 2.12 |
| 13 | Mixed (6182 MWh) | 2.08 |
| 14 | Vertical (5805 MWh) | 2.08 |
| 14 | Mixed (6182 MWh) | 2.03 |
| 15 | Vertical (5805 MWh) | 2.03 |
| 15 | Mixed (6182 MWh) | 1.99 |
| 16 | Vertical (5805 MWh) | 1.99 |
| 16 | Mixed (6182 MWh) | 1.94 |
| 17 | Vertical (5805 MWh) | 1.95 |
| 17 | Mixed (6182 MWh) | 1.9 |
| 18 | Vertical (5805 MWh) | 1.91 |
| 18 | Mixed (6182 MWh) | 1.85 |
| 19 | Vertical (5805 MWh) | 1.86 |
| 19 | Mixed (6182 MWh) | 1.81 |
| 20 | Vertical (5805 MWh) | 1.82 |
| 20 | Mixed (6182 MWh) | 1.76 |
| 21 | Vertical (5805 MWh) | 1.78 |
| 21 | Mixed (6182 MWh) | 1.72 |

| | | |
|---|---|---|
| 22 | Vertical (5805 MWh) | 1.74 |
| 22 | Mixed (6182 MWh) | 1.67 |
| 23 | Vertical (5805 MWh) | 1.7 |
| 23 | Mixed (6182 MWh) | 1.63 |
| 24 | Vertical (5805 MWh) | 1.66 |
| 24 | Mixed (6182 MWh) | 1.58 |
| 25 | Vertical (5805 MWh) | 1.62 |
| 25 | Mixed (6182 MWh) | 1.54 |
| 26 | Vertical (5805 MWh) | 1.58 |
| 26 | Mixed (6182 MWh) | 1.5 |
| 27 | Vertical (5805 MWh) | 1.53 |
| 27 | Mixed (6182 MWh) | 1.46 |
| 28 | Vertical (5805 MWh) | 1.5 |
| 28 | Mixed (6182 MWh) | 1.41 |
| 29 | Vertical (5805 MWh) | 1.46 |
| 29 | Mixed (6182 MWh) | 1.37 |
| 30 | Vertical (5805 MWh) | 1.42 |
| 30 | Mixed (6182 MWh) | 1.33 |