

Article

Policy and Financial Implications of Net Energy Metering in Arctic Power Systems: A Case Study of Alaska's Railbelt

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Abstract

The transition toward sustainable energy in Arctic and subarctic regions requires innovative approaches that account for both the unique geographical conditions and the economic and policy challenges associated with isolated power systems. This study examines how net energy metering (NEM) and net billing schemes influence distributed solar photovoltaic (PV) adoption and financial performance among utilities in Alaska's Railbelt. The Railbelt, which supplies power to three-quarters of the state's population, remains heavily reliant on natural gas and exhibits limited renewable penetration compared to other arctic regions. Using a stochastic risk-based modeling framework with Monte Carlo simulations and the Bass diffusion model, the analysis estimates the 15-year financial impacts of different NEM adoption scenarios on utilities. Results show that while NEM drives PV adoption through higher compensation for exported generation, it also increases potential revenue losses for utilities compared to net billing. Policy innovations like those introduced in Alaska's House Bill 164 (HB 164), which establishes a reimbursement fund to mitigate utility revenue losses, indicate that regulatory work is being designed to balance distributed generation incentives with economic sustainability. This work provides a baseline for understanding how a policy framework influences both utility and consumer economics in terms of NEM and solar PV adoption in Arctic and subarctic systems.

Keywords: net energy metering; solar PV; arctic energy; utility economic modeling; electricity tariffs



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1. Introduction

Solar power has emerged as an important driver of the global energy transition, driven by rapid technological advances, falling costs, and strong policy support. Solar power is a key enabler of the UN Sustainable Development Goal 7 (Affordable and Clean Energy), as it expands access to electricity in both grid-connected and off-grid contexts while reducing reliance on fossil fuels. The global PV cumulative installed capacity grew by 37.5% between 2023 and 2024, reaching over 2.2 terawatts (TW) [1], highlighting the accelerating pace of deployment. In 2024, 75% of new renewable generation capacity installed was from PV [1]. Solar power has become the biggest source of renewable power in countries with good solar conditions [2], and although not as popular in the Arctic, it has also expanded there [3].

Arctic regions encounter unique problems when it comes to the green energy transition due to isolated grids, large distances, extreme winter conditions, and gaps in technological

research. Residents in these regions frequently encounter issues with energy security during harsh winter weather, leading them to rely on back-up diesel generation during outages. In the worst cases, residents endure extended periods without electricity, posing serious safety risks to health and infrastructure. As more individuals rely on their own energy generation, it raises important questions about how this trend will affect the operation and stability of utility companies. These effects have unique implications in the context of small regional grids, where the impacts of energy-independent users will be more noticeable due to limited scale and flexibility.

The expansion of solar power is supported by a wide range of incentives like tender processes and Power Purchase Agreements (PPAs) targeting industrial customers and net metering or net billing schemes available both to industrial and residential customers [1,4]. Net metering and net billing emerged as ways to reimburse prosumers—customers who both produce and consume electricity—with solar PV for the excess of electricity that they exported to the grid. It has been shown that both schemes when paired with a flat volumetric tariff result in cross-subsidization of prosumers by regular consumers (without solar PV) [5,6].

In the early 2010s, when solar PV penetration on the electricity market was still limited, concerns about the so-called “utility death spiral” were often dismissed as misconceptions, since the number of prosumers remained too low to materially affect utility revenues [7]. However, as the cost of PV technology has fallen, electricity prices have increased and thus adoption rates have accelerated, these earlier assumptions warrant re-examination. The growing scale of residential PV installations increases the likelihood of revenue erosion under certain tariff structures [5,8–10].

In this paper, we analyze how the pricing of distributed energy resources (DERs) via net metering could affect the financial stability of utilities on Alaska’s Railbelt, a region defined by an electrical grid that extends from the southwestern coast of the Kenai Peninsula, north 1100 km to the interior town of Fairbanks (see map in Figure 1). This paper explores the potential impacts that NEM can have on smaller regional grids. A case study for the Alaskan Railbelt region was used to examine how NEM could financially impact electric utilities if different levels of solar PV adoption occur. The study applies a stochastic risk-based modeling framework to assess how NEM reforms influence both prosumer PV adoption and utilities financial resilience.

This paper is structured as follows. In Section 2, we present an overview of rate design for the distributed energy system. In Section 3, we introduce the case of Alaska’s Railbelt. Section 4 presents the methodology, and Section 5 presents the results and a discussion. We conclude in Section 6.

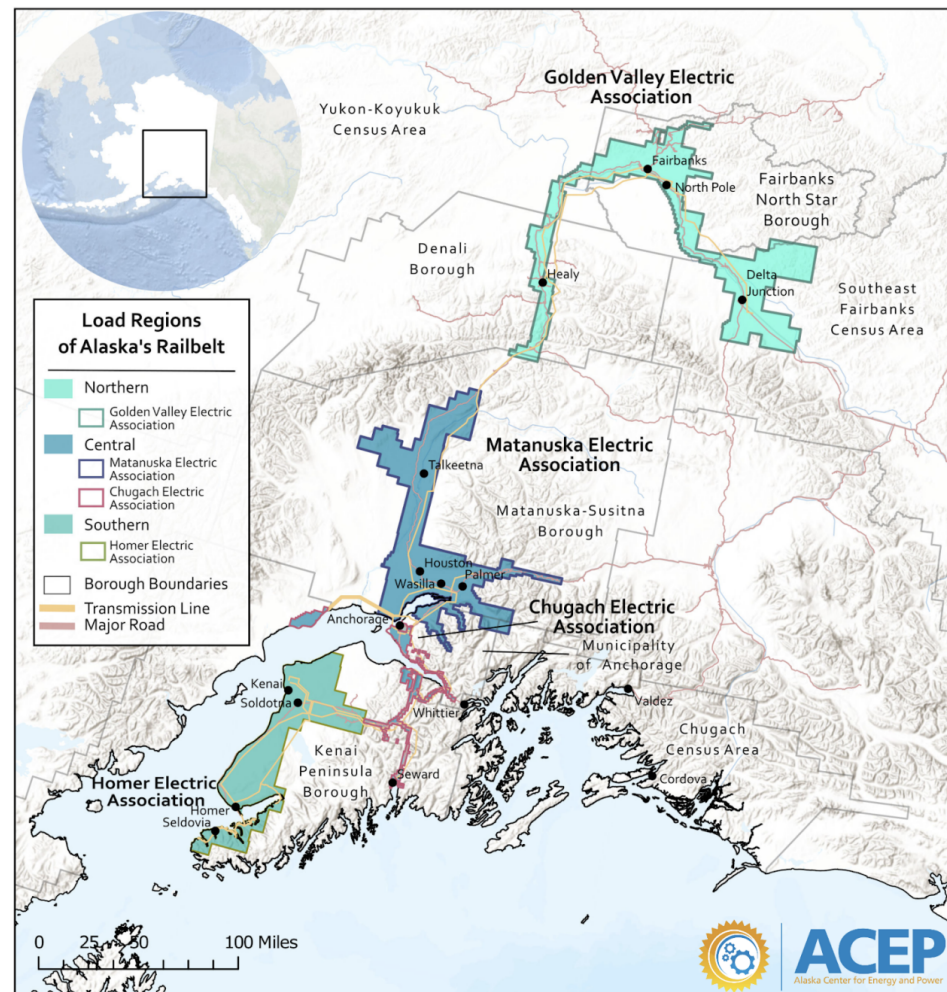


Figure 1. Map of Alaska Railbelt electrical grid, the state of Alaska's largest grid, including the four major utilities on the grid and the regions they serve [11]. Also included in the diagram are transmission lines, showing the connections between the regions. Some of the state borough boundaries lines are also shown. Fairbanks is located approximately 225 km south of the Arctic Circle line ($66^{\circ}33' \text{ N}$).

2. Rate Design for Distributed Energy Systems and Its Challenges

Rate design defines how electric utilities recover their costs and allocate charges among customer classes, and it lies at the heart of current debates on integrating distributed renewable generation. Traditionally, electricity tariffs have relied on volumetric pricing—charging customers per kilowatt-hour (kWh) consumed, with only a small fixed monthly component. This structure functioned effectively in vertically integrated systems with centralized generation, where revenues scaled with energy sales. However, the steady uptake of solar PV systems, supported by diverse policy instruments (such as renewable portfolio standards, investment tax credits, and net metering schemes in the United States) and feed-in tariffs and emerging solar roof mandates in Europe [12], has fundamentally altered the relationship between utilities and consumers. The rise of prosumers challenges traditional rate design by reducing the volume of grid-purchased electricity while maintaining reliance on shared infrastructure. This creates a revenue erosion problem for utilities and raises concerns about cost shifting, where non-solar customers bear an increasing share of network costs.

The question of how to compensate prosumers for the electricity they export to the grid has driven the evolution of two main policy mechanisms: net metering and net billing. Net metering, one of the most widespread approaches, credits exported electricity at the full retail

rate, effectively allowing one-for-one energy exchange between prosumers and the grid [2]. Policies that use net metering to incentivize solar power uptake have been implemented in several US states and countries like the Netherlands, Italy, Chile, and Brazil [13].

By contrast, net billing compensates exports at a lower rate—typically the wholesale market price or a regulated buyback tariff reflecting the utility’s avoided cost of generation—thereby reducing the credit value of surplus production [14].

Under both schemes, the pricing of exported energy may follow traditional flat rates, time-of-use tariffs, or dynamic structures linked to hourly wholesale prices [8].

In almost all US states, the cost of energy and the network is recovered via bundled volumetric rates (in US utilities both produce energy and take care of distribution, whereas in Europe, due to electricity market reforms, there was an unbundling of services, and distribution is operated separately from generation) [15]. As network costs are charged in relation to the kWh of electricity consumed from the grid, distribution system operators (DSOs) recover these costs by increasing distribution charges to all tariff payers [5]. Therefore, prosumers reduce their consumption of grid electricity while also paying lower network charges. To recover those losses, utilities charge higher distribution fees to all consumers, thereby creating a system where traditional consumers subsidize prosumers [5,6,15,16] and contribute to the so-called utility death spiral [6,13,17,18]. In addition, it has been shown that energy storage without adjusted network tariffs will contribute to the utility death spiral [19].

Dynamic network tariffs are reflecting the changing demand for grid usage and congestion conditions and can become a tool for managing the power grid, alleviating congestion, and encouraging flexibility. Among types of dynamic tariffs, there are time-of-use pricing, real-time pricing, critical peak pricing, and critical peak rebates. The critical peak pricing designates high demand hours with higher prices to reflect that demand. Meanwhile, the critical peak rebates offer a discount for a reduced consumption instead of high prices during demand in critical hours [20,21].

Ultimately, the challenge of rate design under distributed generation lies in achieving a balance between promoting renewable energy adoption and maintaining the financial stability and fairness of the electricity system—a balance that is particularly critical in isolated grids such as Alaska’s Railbelt, where high fixed costs and limited interconnection amplify the revenue impacts of prosumer participation.

3. Alaska’s Railbelt Case Study

Unique geographic, climatic, and infrastructural conditions shape electricity consumption patterns and associated energy burdens across Alaska’s Railbelt region. The Railbelt faces some of the highest electricity costs in the United States. Recent analyses demonstrate that the energy cost burden is particularly pronounced in the Fairbanks North Star Borough (FNSB) (see map in Figure 1), where households may spend up to 10% of their income on energy expenditures, the highest proportion along the Railbelt [22,23].

Residential demand in the region is shaped by multiple end uses, with primary contributions from lighting, appliances, refrigeration, electronics, space heating, and domestic hot water systems. Seasonal variation in consumption is pronounced, reflecting Alaska’s extreme daylight cycles. Demand rises substantially during the winter months due to extended hours of darkness, increased indoor activity, and a higher reliance on electric heating systems. In parallel, concerns over reliability during winter have led many households to maintain backup diesel generators to ensure continuity of power supply during outages.

An emerging challenge to electricity reliability and affordability is the decline of local natural gas resources in Cook Inlet, which serves as the dominant local energy source, supplying over 60% of the generation (see Figure 2) [24,25]. In particular, shortages

during a cold snap of the winter 2023/24 have increased energy security awareness among consumers on the Railbelt [26]. This decline raises concerns about general supply security and has prompted greater attention to diversifying the energy mix. Among emerging trends, the gradual but steady increase in residential adoption of distributed solar photovoltaic systems suggests that households are seeking to offset high costs, which might be affected by depletion and further increase, as well as to improve resilience. While solar output is highly seasonal, its growing presence reflects broader shifts toward decentralized energy generation across the Railbelt. Together, these developments underscore the urgency of accelerating diversification efforts to maintain both reliability and affordability in Alaska's evolving energy landscape.

In 2009, the Regulatory Commission of Alaska (RCA) introduced the state's first net-metering regulations that took effect in June 2010. This required electric utility companies with annual retail sales of 5 GWh or greater to offer net-metering to its customers [27]. More recently, Alaska State Legislature introduced HB 164 in March 2025, titled "Net Metering Program & Fund," that proposes to shift the compensation mechanism for distributed generation on the Railbelt from net billing toward net metering [28]. The bill would require load-serving entities with significant retail sales to offer consumer-generators monthly crediting of exported energy at rates equivalent to what those customers pay for electricity consumption (i.e., retail rate) rather than lower wholesale or avoided-cost rate. It also would permit rollover of credits across months up to an annual true-up date (31 March of each year), enabling surplus summer generation to offset usage in darker months, rather than forfeiting excess at the month's end. In parallel, the bill establishes a net metering reimbursement fund through which utilities may seek recovery of lost revenues due to expanded net metering, subject to regulation by the Alaska Energy Authority (AEA) and oversight by the commission.

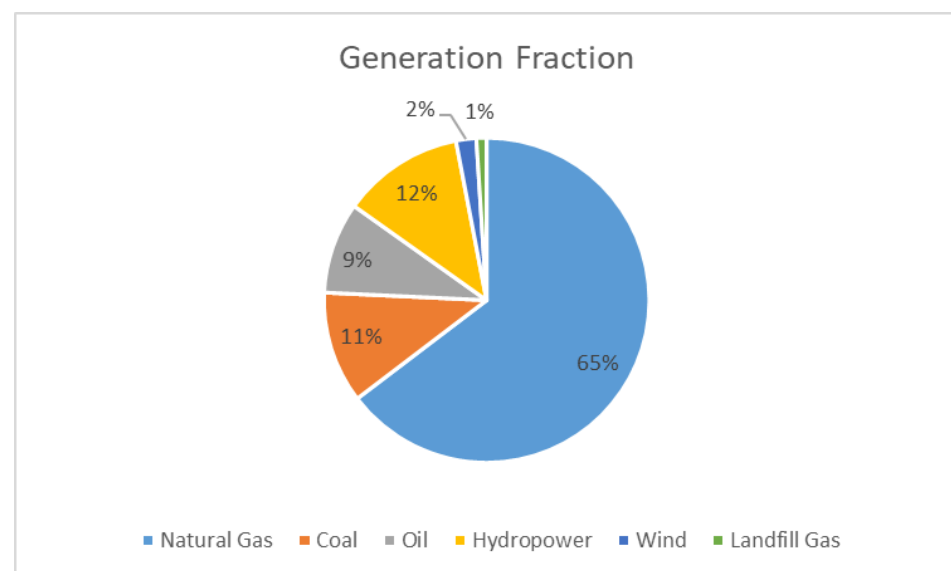


Figure 2. The 2022 primary energy mix of the Railbelt utilities. Data sourced from [25].

Although the legislature has not issued an explicit statement of intent for HB 164, it appears that the bill was tailored to Alaska's unique needs, reflecting the state's geographical and seasonal characteristics that cause distinct variations in solar generation annually. Unlike most regions, where policy typically transitions from net metering to net billing as solar adoption grows, Alaska has followed the opposite path. Because the state saw limited early solar development, it is speculated that regulators moved from a net-billing structure to net metering in an effort to accelerate distributed PV growth by switching

to a scheme that increases prosumer compensation [29]. This reverse progression reflects Alaska’s unique position as a late-adoption market, where policies are being adapted not to curb excessive solar penetration, but to encourage it. Furthermore, the solar penetration in the state remains minute; therefore, challenges like cost-shifting and the “duck curve” are not as pressing as they are in higher solar penetration states like California or Arizona, likely leading to this uncommon policy change. In this context, the annual credit expiration in March likely reflects an effort to encourage solar adoption by enabling summer surplus generation to offset winter consumption. Meanwhile, the reimbursement fund—while administratively complex and relatively novel—drives utilities to quantify economic impacts under a standardized method, in turn generating more accurate data to inform future policy decisions. This also addresses concern over potential rate impacts from NEM as the fund suggests a mechanism for utilities to recover modest losses without unfavorable rate cases [30].

To contextualize the different credit rates of net metering and net billing, the average retail cost of electricity in the Railbelt is around US\$0.23 per kWh, while the avoided cost rate credit is just a fraction of the retail rate at around US\$0.055 per kWh. Table 1 gives a visual representation of the significant difference between the retail rate and the avoided cost rate. Unlike large, interconnected power systems, the Alaskan Railbelt operates with limited interconnection and relies heavily on local generation resources. This smaller scale means that the financial and operational impacts of distributed solar adoption are felt more directly, as there are fewer consumers across which costs can be spread. The Railbelt also lacks the flexibility that larger grids have to balance intermittent renewable generation, making it more vulnerable to revenue losses and system instability under high levels of NEM participation. Learning how to balance these dynamics is not only critical for Alaska but also for other Arctic and subarctic regions where isolated grids face similar constraints.

Table 1. Comparison of average retail and avoided cost rates for Alaska Railbelt utilities.

Rate Type	Rate (US\$/kWh)
Retail Rate	0.23
Avoided Cost Rate	0.055

Despite the Railbelt region only covering a small fraction of the state, the area’s grid connects around 75% of Alaskan residents to electrical power, making it the state’s largest grid [11]. The region consists of both urban and remote communities, with the cities of Anchorage and Fairbanks being home to a large portion of the state population. Meanwhile, Homer, Seward, and Wasilla, have populations of less than 10,000 [31]. Figure 1 shows the four utilities that are interconnected within the region: Homer Electric Association (HEA), Golden Valley Electric Association (GVEA), Matanuska Electric Association (MEA), and Chugach Electric Association (CEA) [11]. These electric utilities are regulated by the RCA, who also works with the AEA in terms of the state’s energy policy [32,33].

4. Materials and Methods

4.1. Economic Modeling Approach

This study adapts the stochastic framework presented by [13], which integrates Monte Carlo simulations, the Bass diffusion model, and a risk-based cost-benefit framework to estimate the present value of electric utilities’ accumulated cash flows. This method is applied in a case study with the aim of quantifying revenue losses due to net metering for Alaska Railbelt utility companies. The model used data collected from four utilities in the Railbelt, i.e., HEA, CEA, MEA, and GVEA. Several assumptions were required to determine values for the factors used in this analysis. Table 2 at the end of the section

summarizes these values, and additional details regarding certain assumptions and data sources are provided throughout this section and within Appendix A.

First, to determine differences in prosumer savings, values for average PV system size, installation costs, and annual unit generation are established. Historical data, given in Table A1, was used to give an estimate for the average system size of a PV unit in the Railbelt. The solar PV system price is modeled using an exponential decay function (Equation (A1)) based on average US installation cost data, as Alaska-specific pricing information is limited. The choice to use exponential decay to model the unit prices over time is supported by data from [34,35]. The following equation (Equation (1)) serves as the basis for estimating the annual energy generated by a single PV system in the region.

The average annual energy generation, $E_G(t)$, of a single PV system is calculated according to Equation (1):

$$E_G(t) = 365.25 \cdot I \cdot P_A(t) \cdot PR \cdot (1 - \tau)^t \quad (1)$$

where

- $E_G(t)$ is the average annual energy generated by a single PV system in year t (kWh);
- I is irradiance ($\text{kW}/\text{m}^2/\text{day}$). Due to limited irradiance data for Arctic and subarctic regions, assumptions were necessary to determine the value of I . The average irradiance used in this study was derived from Tables A2 and A3 and an irradiance mapping of Alaska [36]. While the Railbelt spans a broad area, locations such as Homer, Seward, and Fairbanks may experience irradiance levels that differ significantly from Anchorage. Although Juneau is outside the Railbelt, its data illustrates the substantial seasonal variability in Alaska);
- $P_A(t)$ is average installed power of a Railbelt PV system(kW);
- PR is performance ratio (%);
- τ is degradation rate (%).

Next, cost differences in net metering (NM) and net billing (NB) can be demonstrated by modeling prosumer benefit equations, which give the cost benefits of a single prosumer for under either scheme. In the case of net metering, shown in Equation (2), all electricity generated is valued at the retail tariff $T_e(t)$, regardless of whether it is self-consumed or exported. Under net billing, Equation (3), only the fraction ξ that is self-consumed offsets retail purchases, while any excess generation $(1 - \xi)$ is credited at a lower compensation rate T_{CR} , which is typically closer to wholesale value.

$$B_{T,NM}(t) = E_G(t) * T_E(t) \quad (2)$$

$$B_{T,NB}(t) = E_G(t) \left((\xi * T_E(t)) + ((1 - \xi) * T_{CR}) \right) \quad (3)$$

where

- $B_T(t)$ is the prosumer benefit in year t (US\$);
- ξ is the self-consumption rate between the PV system's generation and the prosumer's consumption (%) (the self-consumption rate (ξ) is assumed based on data from [37]. Alaska is expected to have a higher self-consumption rate compared to non-Arctic regions due to its unique seasonal daylight patterns and limited solar export opportunities);
- $T_E(t)$ is the electricity tariff rate in the region (US\$/kWh)
- T_{CR} represents the rate at which prosumers are compensated at for any excess generation (US\$/kWh). Note that this is not a cash payout, but rather a credit on future bills.

In addition to PV installation costs, prosumers must also deal with costs referring to (i) operation and maintenance and (ii) inverter exchange. In this study, the inverters are exchanged in the 13th year so the cost of replacement is only accounted for in year 13 [38]. The annual operational and maintenance costs for the prosumer in year t is given by Equation (A2). While Equation (A3) provides the yearly cash flows, these values must be adjusted to reflect their present value by incorporating the consumer-generator's cost of capital. This is done by discounting each year's cash flow according to the expression shown in Equation (A4).

The results from these calculations allowed for the Monte Carlo simulation of the benefits and costs associated for a prosumer operating PV panels under NEM in this region. Using the prosumer cash flows, historical PV adoption data, and the Bass diffusion model, an estimate of the number of PV adopters over the next 15 years was produced (demonstrated by Equations (5) and (A5)). The Bass diffusion model is a mathematical model used to forecast the adoption of new products or technologies [39]. Other studies, including [40], utilize the model to understand residential solar adoption trends. Based on this adoption forecast, the costs and benefits of NEM on the utility was able to be calculated. Together, this data allowed for the calculation of the present value of accumulated cash flows for each utility over the 15 year time period.

The energy fed into the network by the PV systems and the cost benefits that relate to this energy are presented in Equations (A6) and (A7). This represents the avoided cost the utility experiences by not having to purchase or produce energy. Although the utility does compensate the consumer-generator for the energy produced, this is taken into consideration later because in cost-benefit analysis frameworks, the gross benefits are calculated before subtracting costs [41]. Although minimal, transmission and distribution loss reduction should be taken into consideration due to the energy consumption taking place at the point of generation [42]. Annual benefits due to the reduction in energy loss in distribution and transmission due to PV system implementation are calculated by Equations (A8) and (A9). The benefit referring to the avoided expansion in the transmission system is calculated according to Equation (A10).

The lost revenue resulting from consumer-generators reducing or eliminating their electricity purchases from the utility must also be accounted for. The reduction of utilities' sales due to on-site generation from PV systems is given by Equation (A11). The cost at which the utility decides to compensate the consumer-generators for their excess electricity fed into the grid must also be considered. The cost related to the excess energy compensation payment is given by Equation (A12). Note that consumers receive this compensation as credits on future bills. If the credits are not used before their expiration date, they may not result in a cost to the utility.

This method estimates the total financial impact of installing PV systems by assuming that each system contributes equally to the utility's benefits and costs, and that all systems have the same average power output. The cash flows from these systems over the analysis period are then discounted to their present value. The present value of accumulated utility cash flow is calculated according to Equation (4).

$$PV_{ACF} = \sum_{t=0}^{15} \left(\frac{B_{ET}(t) \cdot \Delta N(t)}{(1 + WACC)^t} + \sum_{i=0}^t \Delta N(i) \cdot \frac{B_S(t-1) - C_{RM}(t,1) - C_E(t-1)}{(1 + WACC)^t} \right) \quad (4)$$

where

- PV_{ACF} is the present value of accumulated utility cash flow (US\$), given by the sum of the present value of cash flow for each year in the analysis period;

- $B_{ET}(t)$ is the benefit referring to the avoided expansion in the transmission system in year t (US\$);
- $B_S(t - i)$ is the sum of the benefits from the reduction in energy loss in distribution and transmission systems and the benefit referring to energy injected in the distribution network;
- $C_E(t)$ is the cost referring to energy injected in the distribution network, in year t , by PV system (US\$);
- $C_{RM}(t, i)$ is the cost, in year t , related to the reduction of utilities' market, due to the PV systems installed in year i (US\$).
- $\Delta N(t)$ is the number of PV system adopters in year t ;
- $\Delta N(i)$ is the number of PV system adopters in year i ;
- WACC is the weighted average cost of capital of electric energy utility companies (US\$);
- $\Delta N(0)$ is set equal to the initial number of adopters in year $t_0 - 1$, or the amount of adopters already present in the system, before analysis.

Figure 3 displays the overall flow of variables and steps used in the economic modeling of the net metering impacts in Alaska's Railbelt. The model uses historical data, randomized variables, system costs, and customer adoption behavior to simulate cash flows, payback periods, and adoption trends for the PV systems within the region. These outputs give results for both consumer-generator and utility finances. On the consumer side, the model estimates the timeline of returns which then identifies potential adopters' sensitivity. On the utility side, the average injected energy, system costs, and adoption levels are used to estimate the benefits and costs for utilities under NEM policies. This framework makes it possible to explore how distributed generation affects both the consumer-generators and utilities financially over a chosen period of time.

Table 2. General technical and financial data relating to parameters used in Equations (1) through (4), and (A1) through (A12).

Symbol	Variable	Value	Unit
n	Number of simulations of Monte Carlo method	2000	—
T	Analysis period	15	years
N_C	Number of consumer units that receive credits	2985 ^a	PV units
$M_{0,10}$	Number of capable system adopters (10%)	20,000	adopters
L	PV systems lifespan	25 ^b	years
C_I	Cost of inverter exchange	9.6 ^c	% of system price
$C_{O\&M}$	Operation and maintenance cost	1 ^d	% of system price
PR	Performance ratio	70 ^e	%
τ	Degradation rate	0.5 ^d	%
I	Irradiance	3.93	kWh/m ² /day
$V_P(t)$	Valuation of avoided expansion in transmission	111 ^f	US\$/MW
$V_{E_I}(t)$	Valuation of energy injected by PV	55 ^g	US\$/MWh
$V_{E_C}(t)$	Valuation of excess energy credit rate	55 ^g	US\$/MWh
$T_{CR}(t)$	Consumer-generator compensation rate	0.055 ^g	US\$/kWh
P_D	Reduction in distribution losses	7.5 ^h	%
P_T	Reduction in transmission losses	7.5 ^h	%
ξ	Self-consumption ratio	80 ^g	%
CC	Cost of capital for consumer-generator	4 ⁱ	%
ν	Months generation exceeds use	50 ^g	%
WACC	Weighted average cost of capital of electric utilities	7.7 ^j	% per year

^a Data from [43–46]; ^b from [47]; ^c based on data from [48] of average inverter cost from 2010–2023;

^d data from [13]; ^e based on results from [49]; ^f data from [50]. Price adjusted for inflation; ^g from [37];

^h from [51]; ⁱ from [52]; ^j based on data from [53].

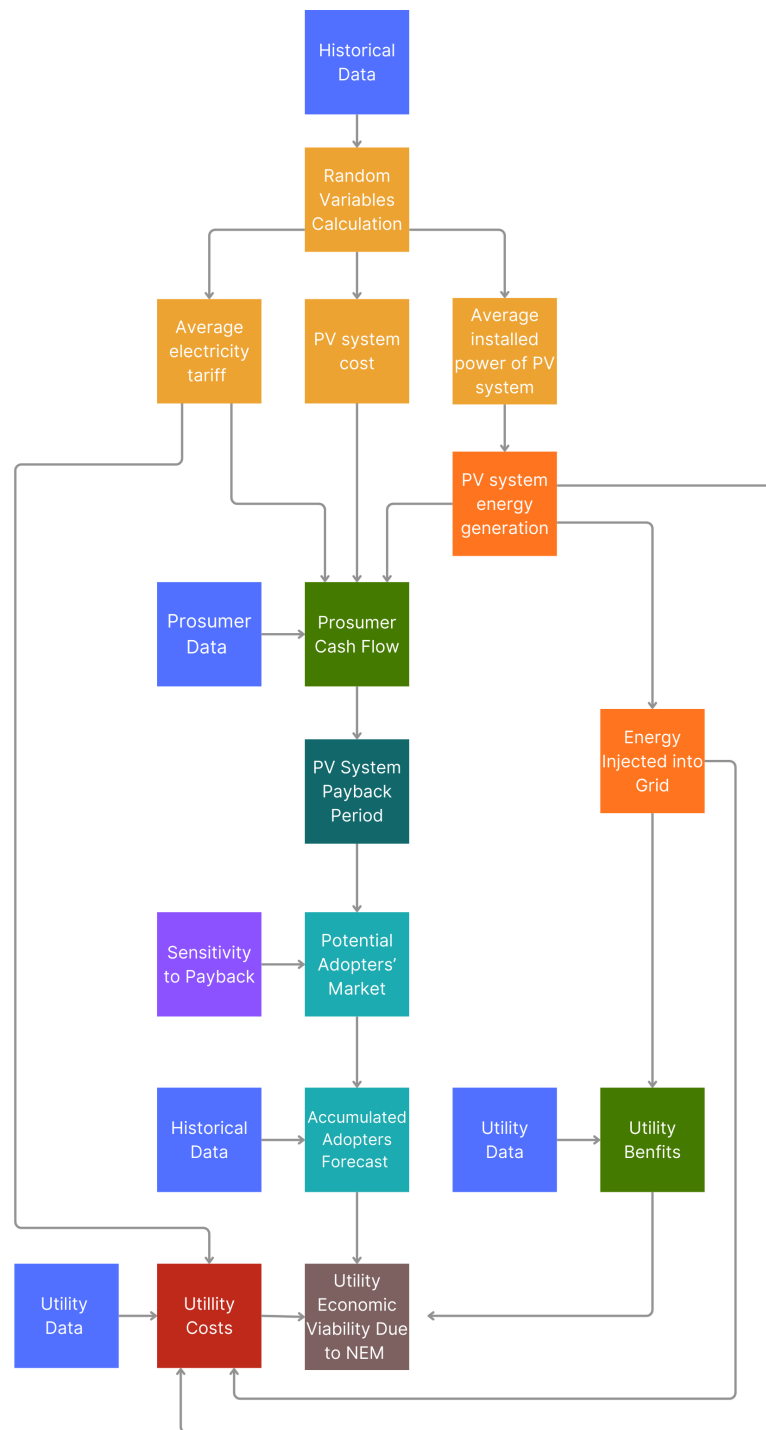


Figure 3. Block diagram depicting flow of variables and calculations for methods relating to the economic modeling.

4.2. Case Description

Due to the state's change in NEM regulation, two separate cases of economic modeling are performed to analyze the estimated effects of PV solar NEM under the former regulation, best described as net billing and again, under the newly instated regulation, presented in HB 164, which aligns with the term net metering. Under each of the two cases, six scenarios are presented to showcase a range of results that are dependent on consumers willingness to adopt solar PV (highlighted in Table 1). The six scenarios represent an array of percentages that correspond to the willingness to adopt. The value of s , or sensitivity to payback, determines the fraction of capable households, M_0 , that are willing to adopt based on

the estimated payback period (capability refers to residents who have suitable roof space, favorable solar exposure, the financial means to invest in a system, and live in areas where interconnection is feasible; it excludes households facing significant physical barriers, such as heavy shading or structural limitations, as well as those restricted for financial reasons) [54]. Equation (5) shows the relationship between the capability of the market by linking it directly to the technology's economic attractiveness. A higher value of s implies that adoption potential decreases with longer payback periods, while a lower value indicates that customers are less deterred by extended payback times. Incorporating this parameter within the Bass diffusion framework allows the model to reflect how economic conditions dynamically influence consumer behavior.

These scenarios (see Table 3) are included in this study as a way to illustrate how varying sensitivity to payback influences adoption rates and thus the financial effects of end user generation on utilities. The value of s is determined based on an average payback time, so the two cases have s values based on average payback time of 8.5 years for the net billing and 7 years for net metering. It is important to note that because payback periods decrease over time, the fraction of consumers willing to adopt changes dynamically, because the sensitivity parameter, s , is fixed. As a result, the number of adopters may exceed the initially estimated fraction, since improving economic conditions, i.e., shorter payback times, make PV adoption more attractive as time goes on.

$$\text{Fraction of } M_0 \text{ willing to adopt} = e^{-s \cdot P_B(t)} \quad (5)$$

where

- M_0 is the total PV systems potential adopters' market, which represents the total residential units that have the capacity to adopt a PV system;
- $P_B(t)$ is the payback of a PV system installed in year t (years);
- s is the constant that represents sensitivity to payback.

While this study provides insight into the economic impacts of PV adoption under different regulatory frameworks, there are several limitations that should be noted. First, the analysis did not explicitly model electricity price growth tied to declining Cook Inlet gas production; instead, inflation-based adjustments were applied to reflect general cost increases. This simplification may underestimate potential future price volatility and its influence on PV adoption and utility revenues. Second, the model simplifies the addition of HB 164's rollover credit mechanism, which allows excess generation credits to carry over until 31 March. This credit mechanism could significantly affect prosumers' costs and benefits during winter months if substantial credits accumulated over the summer are applied, which in turn would affect payback calculations and utility revenues. The model now gives a conservative estimate for the effects of this mechanism. Third, the solar irradiance value used in this analysis is an estimated average based on state-wide data. Solar irradiance can vary considerably across the Railbelt, particularly between northern locations such as Fairbanks and southern coastal communities like Homer. Incorporating site-specific irradiance data would likely refine the estimated generation and economic outcomes at the utility level. Fourth, the model focuses on revenue impacts but does not account for complexities within the grid that may occur as DER penetration increases [14]. DER can decentralize energy production in ways that improve energy security and grid resilience, which has proven to be helpful in remote or vulnerable areas [55]. However, these advantages must be weighed against the potential drawbacks; poor planning during DER implementation can lead to imbalances in power flows, reverse power conditions, and power quality problems, especially in areas with high solar PV penetration [56]. These issues can be mitigated by strategically locating the placement of DER systems, such as placing them near substations where grid infrastructure is more likely to be better equipped to handle bidirectional power

flows. Although this solution helps in grid stability, this approach may inadvertently lower equity in access to DER benefits, as areas located farther from substations may experience more technical limitations to DER installations. In some cases, implementing DER in these areas could require substation upgrades or new infrastructure installations, which would increase system-wide costs. Due to the complexity of these factors, any additional costs associated with PV integration in the Railbelt are not accounted for in this modeling approach. Finally, the absence of battery storage in the adoption model may underestimate future uptake. Since battery storage is a potential solution to the grid integration challenges discussed above, it is important to note that its benefits are also not incorporated into the model due to the complexity of modeling such interactions. Given Alaska's unique seasonal profile, pairing PV with storage could become increasingly attractive, altering both self-consumption rates and grid injection patterns. These limitations highlight the need for more expansive modeling to fully capture the technical and economic implications of distributed generation in high-latitude, isolated grids.

Table 3. Adoption scenarios below are defined by a payback period (8.5 years for net billing and 7 for net metering), a sensitivity parameter s , the fraction of M_0 willing to adopt, and the number of adopters based on the net billing scheme and the net metering scheme.

Scenario	Fraction of M_0 Willing to Adopt	NB Sensitivity s_{NB}	NM Sensitivity s_{NM}	Number of Adopters
1	$\frac{1}{2}$	0.06	0.08	10,000
2	$\frac{1}{3}$	0.13	0.16	6667
3	$\frac{1}{5}$	0.19	0.23	4000
4	$\frac{1}{10}$	0.27	0.33	2000
5	$\frac{1}{20}$	0.35	0.43	1000
6	$\frac{1}{100}$	0.54	0.64	200

5. Results and Discussion

5.1. Prosumers

Economic modeling of the prosumer cash flows found that the average Railbelt prosumer will have yearly bill savings of around US\$1200 with a 5.5 kW PV system installed under the former net billing compensation scheme and US\$1450 for the same system under net metering. Net metering increases savings by around 20% compared to net billing, which could influence consumer adoption behaviors. Figures 4 and 5 show the estimated payback period according to the systems installation year based on net billing and net metering, respectively. As prosumers save more money under the net metering scheme, it is clear that the associated payback time for that system will be shorter than that of net billing. This is demonstrated in Figures 4 and 5, with the same system installed in 2025 estimated to be paid off almost 2 years sooner with the net metering scheme than with net billing. The US federal Investment Tax Credit (ITC) is taken into account during this time period. The ITC currently credits residents 30% of the installed system cost through 2032. It steps down to 26% in 2033, 22% in 2034, and expires thereafter [57]. These results align with the state's anticipated intent and objectives to transition from its previous compensation scheme regulations to the new NM scheme established under HB 164.

As payback periods influence PV adoption rates, the following plots in Figures 6 and 7 are presented to show the estimated cumulative number of PV adopters in the Railbelt over the next 15 years under the six different 'adoption willingness' scenarios. As a result of the final estimates regarding the financial viability of the Railbelt utility companies being dependent on the levels of PV adoption, this data was calculated. There are only slight differences in adoption rates for the two scenarios, indicating that the slight increase in

prosumer savings under net metering will not strongly influence adoption behaviors in the Railbelt. This is mainly due to Alaska prosumers having a high annual self-consumption rate from their PV systems. While these systems generally produce more electricity than the residence consumes during the late spring and summer months, the bulk of electricity is used in early spring, fall, and winter when PV production is moderate to low. This implies that residences will consume more electricity than the system produces resulting in only cost savings from the energy produced, but not additional netted credits.

The adoption scenarios illustrate how consumer sensitivity to payback affects PV adoption. Each scenario is defined by a fixed sensitivity parameter, s , which sets the fraction of eligible consumers, M_0 , willing to adopt at an average payback period of 8.5 years for net billing and 7 years for net metering. In this study M_0 is set to 20,000 to represent that approximately 10% of Railbelt homes are eligible for PV adoption. This 10% figure is a working assumption due to limited data on actual eligibility. The six scenarios are representative of different values of s that indicate the level of willingness to adopt. These scenarios range from high adoption (Scenario 1, $\approx 50\%$ of M_0) to very low adoption (Scenario 6, $\approx 1\%$ of M_0).

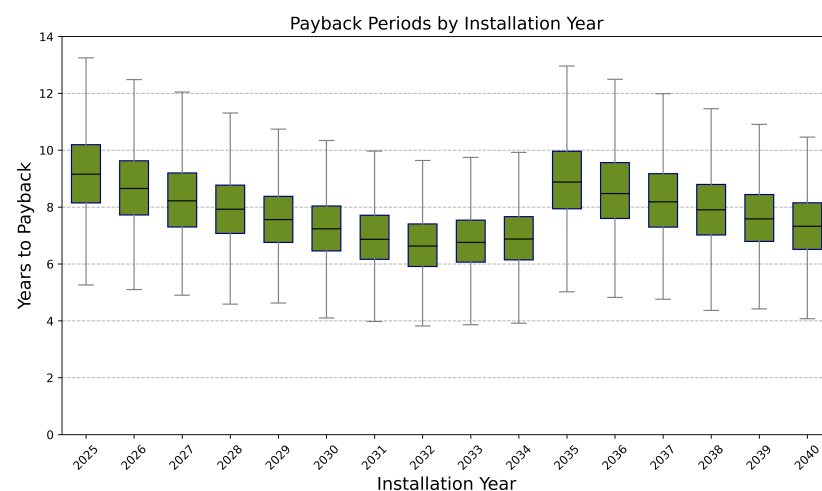


Figure 4. The estimated payback period (in number of years) for PV systems installed in the Alaska Railbelt in year t under the net billing scheme (Pre HB 164). The ITC is taken into consideration for this plot.

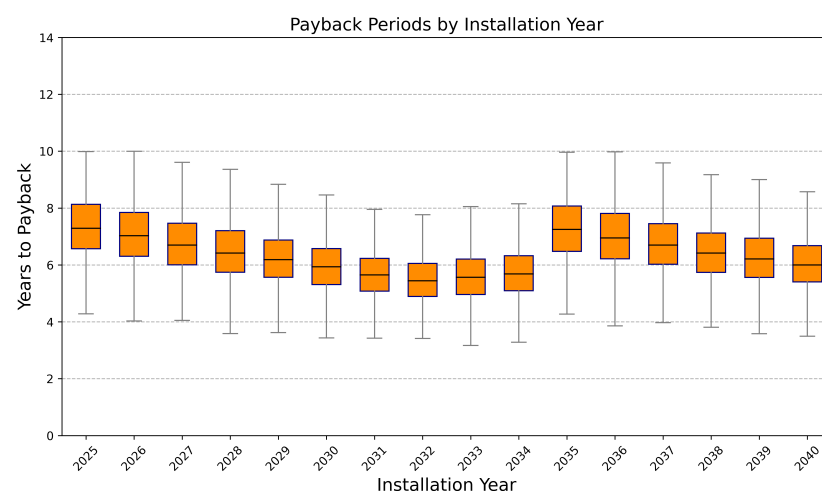


Figure 5. The estimated payback period (in number of years) for PV systems installed in the Alaska Railbelt in year t under the net metering scheme (Post HB 164). The ITC is taken into consideration for this plot.

In terms of high adoption rates, both net billing and net metering scenarios predict that by the end of the study period in 2040, the median number of cumulative adopters reaches over 13,000, with NM just peaking over 14,000. Although this sensitivity level (representing 50% adoption) is highly unlikely, it was included in the model to explore upper-bound outcomes. More realistic sensitivity levels are the ones presented in scenarios 3–5. Scenario 6, while not entirely implausible, represents a highly conservative outcome in which only 1% of the remaining capable market chooses to adopt solar PV. While Scenario 1 shows an 8% increase in adoption, the more realistic mid-level scenario 3 reflects a 5% increase, and scenario 4 only a modest 3% rise. For scenario 6, the difference in the cases is virtually indistinguishable. Even though cost savings increased by roughly 20%, the estimated rise in adoption is not as steep as previously anticipated. These findings suggest that the financial incentives that come with HB 164 alone may not be sufficient to drive rapid growth in participation. Additionally, future regional challenges, like the Cook Inlet natural gas shortage, could drive up electricity prices, and in turn increase the likelihood of DER adoption in the area.

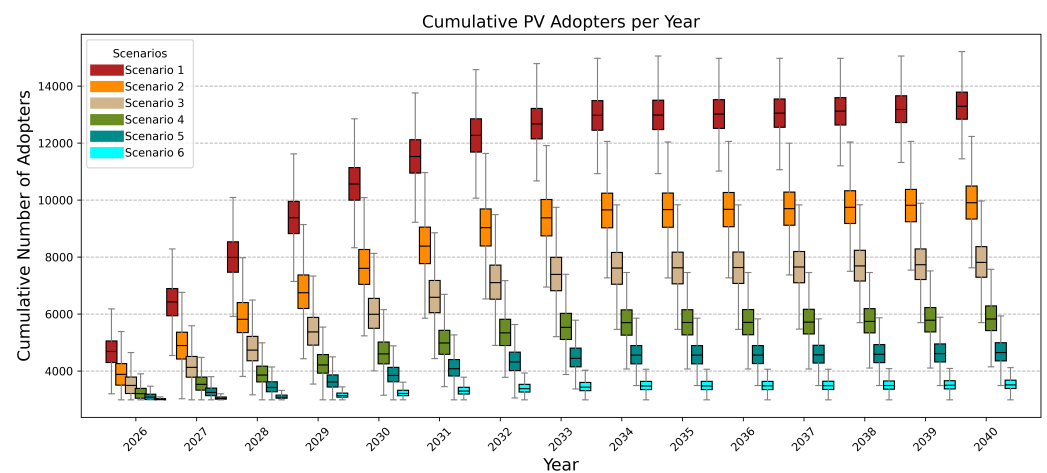


Figure 6. The cumulative number of PV NEM adopters in the Alaska Railbelt under different sensitivity scenarios for the previous net billing scheme (Pre HB164).

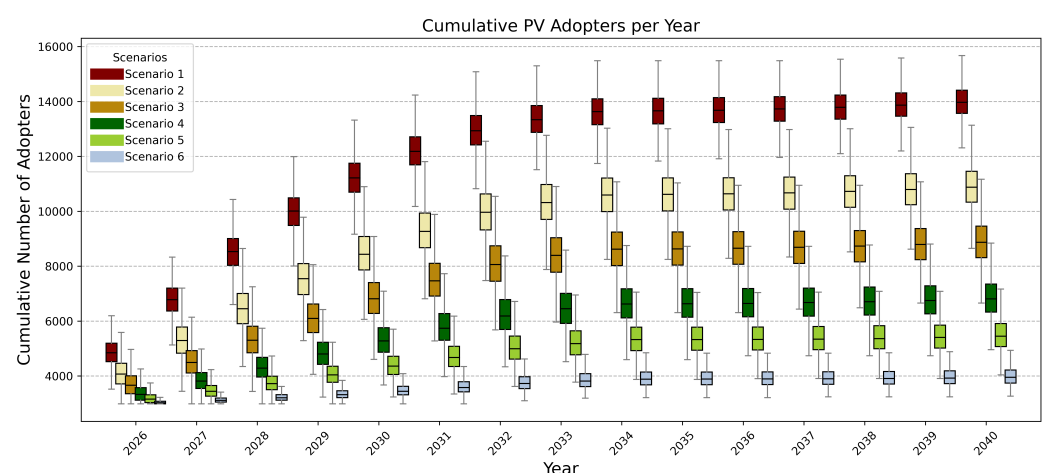


Figure 7. The cumulative number of PV NEM adopters in the Alaska Railbelt under different sensitivity scenarios for the new net metering scheme (Post HB164).

5.2. Utilities

Final estimates regarding financial viability of utility companies in the Railbelt is based on the varying levels of PV adoption. Figures 8 and 9 present the net present

value of accumulated cash flows, PV_{ACF} , for a 15-year period in the Railbelt that were calculated using the discount rate of 7.7% for both cases. The results are based on the previous assumption that 10% of Railbelt households are eligible to adopt NEM. There are six scenarios that represent varying levels of willingness to adopt PV that are analyzed. As adoption levels increase, the negative PV_{ACF} becomes greater in magnitude, indicating more severe losses to the utility. Under the former net billing scheme, scenario 1 yields the largest losses with an expected value of US\$ ≈ -166 million, while scenario 6 minimizes these losses, with an expected value of US\$ ≈ -55 million, only a third of the losses from scenario 1 (shown in Figure 8). Scenarios with higher sensitivity, i.e., 4, 5, and 6, also show a reduced variability in results. This points to a larger uncertainty for the impacts of high-penetration PV adoption, likely stemming from the uncertainty in adoption numbers for low sensitivity scenarios. In terms of the second case, losses resulting from the net metering scheme are naturally greater. Scenario one indicates utility losses of closer to US\$200 million, a 20% increase from net billing scenario one. Comparatively, scenario six under net metering, with a lower estimated loss of US\$70 million, results in a 27% increase from the expected losses from net billing scenario six. These losses do not take into consideration any potential utility reimbursement from the AEA based on HB 164.

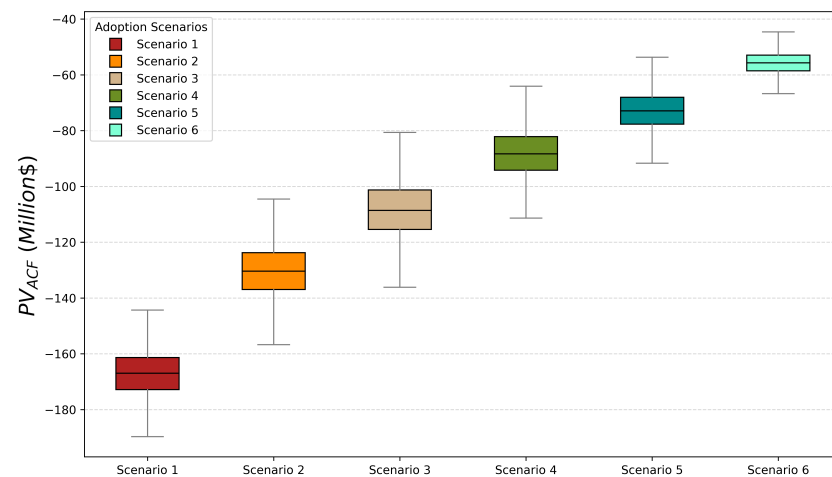


Figure 8. The estimated present value of the 15 year accumulated cash flow from solar PV NEM within the Railbelt utilities under the previous net billing scheme (Pre HB164).

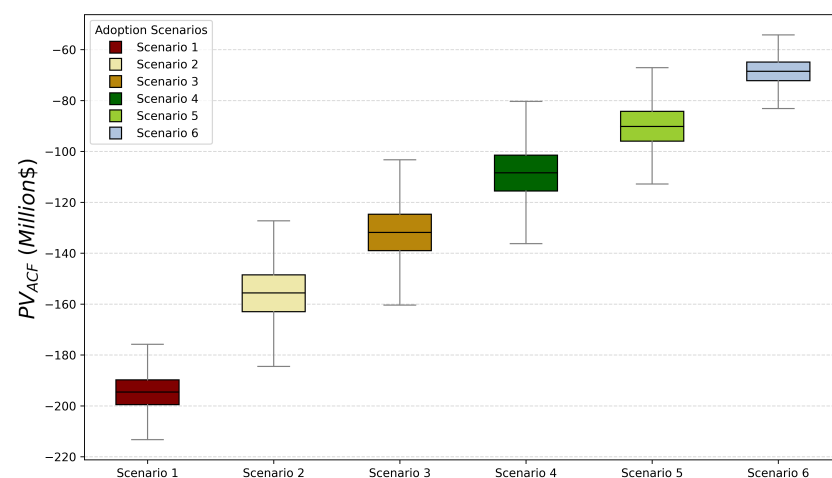


Figure 9. The estimated present value of the 15 year accumulated cash flow from solar PV NEM within the Railbelt utilities under the new net metering scheme (Post HB164).

To parallel these results with historical data from the Railbelt utilities, Table 4 presents the annual operating margins of these companies, as well as giving a combined total and average for each year. The operating margin measures a company's profit per dollar of sales after covering variable production costs like wages and raw materials, but before accounting for interest and taxes [58]. Essentially, it shows how much financial cushion a utility has from its core operations each year. Comparing this to the modeled NEM losses gives a sense of how much room the utilities have to absorb revenue reductions without dipping into other reserves or needing to raise rates. While operating margins do not tell the whole story of a company's finances, they can still provide a useful benchmark for understanding the scale of impact NEM could have on a utility's financial health. The combined average annual margin across all utilities is US\$31.6 million (prices were deflated using an estimated 3% rate based on 2024 consumer price index data [59]), with a standard deviation of US\$11.8 million.

Table 4. History of Alaska Railbelt Utility Annual Operating Margins from 2017 through 2023, adjusted to 2025 US\$ (in millions). Values for each individual company are listed as well as a combined average.

Year	GVEA ^a	MEA ^b	CEA ^c	HEA ^d	Combined	Combined Avg.
2023	0.6	8.6	6.0	0.2	15.4	3.9
2022	14.0	6.5	8.1	1.6	30.3	7.6
2021	14.0	12.4	10.3	3.5	40.2	10.0
2020	16.2	12.4	5.2	5.4	39.1	9.8
2019	5.3	7.1	5.1	4.6	22.1	5.5
2018	7.8	7.1	6.0	3.0	23.9	6.0
2017	25.8	11.0	6.7	6.4	49.9	13.0
Mean	11.9	9.3	6.8	3.5	31.6	7.9
Stdev	8.2	2.6	1.9	2.1	11.8	3.1

^a Data from [60]; ^b data from [61]; ^c data from [62]; ^d data from [63].

Below, Table 5 shows a comparison of the mean projected annual losses under each scenario to the historical combined average operating margin. This allows for an assessment of the relative magnitude of NEM-induced financial impacts.

The results indicate that high levels of NEM adoption would erode a substantial portion of the utilities' financial margin. Scenario 1, representing the highest level of PV participation, results in the most significant impact: mean annual losses of US\$11.1 million and US\$13.0 million. This corresponds to 35–41% of the average historical operating margin across Railbelt utilities. The mid-level adoption, scenario 4, is considered to show the impacts of a realistic adoption estimate based on other region's adoption data. This scenario presents a more balanced future for utility finances. Under scenario 4, losses amount to approximately US\$5.8–7.2 million. This is equivalent to 18–23% of the average historical margin and 38–47% of the minimum margin. Based on the number of adopters by 2040, Scenario 4 would result in approximately 7500 NEM participants. This represents 2.8% of total Railbelt meters currently. At the lowest end of the adoption spectrum, scenario 6 demonstrates the lowest financial impact. Losses under this scenario average US\$3.7 to 4.6 million, accounting for 12–15% of the average historical margin and 24–30% of the lowest annual margin. These levels are well within the range most utilities could absorb without requiring structural changes to rates or programs. As such, these lower middle to low adoption scenarios may represent the most realistic adoption expectations for the Railbelt. Additionally, with HB 164, these losses could be offset due to utility reimbursement through AEA.

Comparing projected NEM losses to historical utility margins helps put the results into perspective. While lower adoption cases seem more manageable, the higher adoption cases could seriously impact utility revenue, making the possibility of cost-shifting more plausible. This shows how important it is for NEM program design to reflect both what's financially realistic and where adoption is likely headed. A more gradual, flexible roll-out with smart rate structures, continued data collection and analysis, and policies that can adapt to stress is the most stable way forward.

These modeling results provide a brief look into the financial dynamics of distributed solar adoption in the Railbelt. In summary, solar PV adopters in the Railbelt region will, on average, have bill savings of around US\$1200–1450 annually for a system installed with a 5.5 kW nameplate capacity. For this size system installed in 2025, the estimated average payback period for this technology is between 7 and 9 years, allowing another 13 to 21 years left of the system's lifetime, with minimal maintenance and operational costs. As adoption increases, the model shows that utilities experience increasingly negative net present values, with higher adoption scenarios generating substantial financial losses. While such extreme cases are unlikely for the region, they highlight potential risks, while the lower-adoption scenarios, which likely better reflect the regions trends, show considerably less risk and more stable outcomes, which could make them more manageable within current financial and regulatory frameworks. PV adoption rates are likely to continue to increase at a steady rate, but will likely begin to plateau at around 2035. This will likely be caused by both a saturation within the market, as well as the ITC credit, which reduces a PV system's cost by 30%, expiring completely at this time. Taken together, these results help contextualize the economic impacts of residential solar adoption and can inform policy approaches that balance prosumer benefits with long-term utility stability.

Table 5. Comparison of projected annual financial losses for Railbelt Utilities under two cases across six scenarios, expressed in millions of dollars (US\$). The table also shows the percentage of average and minimum historical utility margins lost in each case, illustrating the relative impact of losses on utility profitability.

Scenario	Case 1 Net Billing	Case 2 Net Metering	% Avg Margin Lost (C1)	% Avg Margin Lost (C2)	% Min Margin Lost (C1)	% Min Margin Lost (C2)
1	\$11.1M	\$13.0M	35.1%	41.0%	72.1%	84.2%
2	\$8.6M	\$10.4M	27.2%	32.8%	55.8%	67.3%
3	\$7.2M	\$8.8M	22.8%	27.8%	46.8%	57.1%
4	\$5.8M	\$7.2M	18.3%	22.9%	37.7%	47.1%
5	\$4.8M	\$6.0M	15.2%	19.1%	31.2%	39.1%
6	\$3.7M	\$4.6M	11.7%	14.4%	24.0%	29.6%

Overall, the findings reflect the complex trade-offs between promoting renewable energy at the residential level and ensuring that utilities remain financially viable and able to provide reliable service. While this study focuses specifically on Alaska's Railbelt, the results offer broader insights for other Arctic and rural grids facing similar transitions. That said, there are limitations. This work relies on projections that carry uncertainty, particularly around consumer behavior, technology costs of both the system and grid infrastructure, and capable adoption markets. Additionally, the financial model could be updated to reflect a broader range of variables, such as different PV panel types, time-varying compensation schemes, and weather-related performance data.

In addition to the financial questions that are raised, the results also raise operational and regulatory questions regarding grid flexibility and rate design.

5.3. System Flexibility and Policy Implications

In power systems, flexibility refers to the ability to respond to short-term variations in supply and demand, maintaining balance in the face of variable generation from renewable sources and increasing demand [64]. It can be enhanced by well-constructed distribution tariffs and granular pricing of electricity depending on the user location [65]. In the Railbelt context, where the grid is relatively isolated and balancing utilization of resources is limited, rate design influences not only the financial interactions between prosumers and utilities but also the system's operational flexibility.

In remote systems, such as the Alaskan Railbelt, enhancing flexibility through rate design is important not only for maintaining utility revenue adequacy but also for ensuring grid reliability in the face of increasing distributed generation. However, neither flat net billing nor flat net metering schemes provide any incentives for providing flexibility, meaning that prosumers' behavior is not aligned with the wider needs of the grid.

5.4. Energy Justice

Under the new net metering arrangement in Alaska, consumers receive a higher compensation rate for exported electricity compared to the previous net billing scheme. However, under both frameworks, prior analyses have demonstrated the presence of cross-subsidies from non-solar to solar consumers [5,6]. To prevent an increase in retail tariffs and to uphold principles of energy justice, the State of Alaska has established a net metering reimbursement fund to compensate utilities for the additional costs incurred due to the policy change. A potential issue with this approach lies in the financial sustainability of the compensation fund. (The size of the fund is not stated. The regulation defines it as "(1) money appropriated to the fund by the legislature; (2) gifts, bequests, contributions from other sources, and federal money; and (3) interest earned on the fund balance."). As PV adoption increases, utilities' costs rise correspondingly, and the fund itself must be replenished. Thus, the long-term viability of this mechanism depends on both the rate of distributed generation adoption and the structure of electricity tariffs. One alternative to reduce financial strain on utilities is to reform tariff design beyond traditional flat volumetric rates. Ref. [15] demonstrated that bidirectional volumetric tariffs perform more efficiently under distributed generation contexts. In the European Union, the Agency for the Cooperation of Energy Regulators (ACER) similarly recommends avoiding the combination of net metering with volumetric charges, as this approach tends to over-incentivize PV adoption and is often perceived as inequitable [66]. Additionally, a more efficient design is an unbundled tariff structure, separating network, distribution, and supply components [15]—contrary to the current practice in Alaska, where these elements are bundled into a single rate, as is common across much of the United States. Another potential approach involves the introduction of dynamic tariffs, which could enhance the value proposition of energy storage (however, energy storage without adjusted network tariffs will contribute to a utility death spiral [19]) and demand response technologies, like smart meters. However, practical implementation may face social and behavioral barriers, as consumers often perceive dynamic pricing as complex or unfavorable.

6. Conclusions

The results show that while solar PV adoption remains relatively low in the Railbelt, there is a clear tipping point where net metering can begin to significantly impact utility revenues, with greater deterioration happening under compensation schemes based on retail rate crediting. The study found that variations of net metering, like net billing, are better suited to balance the compensation for the prosumers with the financial needs of the utility companies. Economic modeling confirmed that higher adoption rates under

traditional NEM could lead to notable operating margin losses for some utilities, with extreme levels of adoption being unsustainable. Policy structures like Alaska’s HB 164, which introduce reimbursement mechanisms and credit expiration, indicate that policy adaptations are not only happening, but are crucial in ensuring utility viability without diminishing DER adoption.

There are many avenues to explore in future work to address the intricacies of distributed generation in Arctic and subarctic regions. This begins with more thorough data collection and research on solar PV and other distributed generation in high-latitude regions, as well as comparative analyses on the financial impacts of different compensation schemes and rate structures. Further work could explore the technical, social, and financial roles of battery storage and community solar in shaping NEM outcomes as well as a broader look at additional social, policy, or market factors that could influence adoption or utility risk. Finally, analysis of the technical requirements and potential grid upgrades necessary to support higher levels of DER, and how those should be reflected in economic modeling, is critical in developing a full understanding of NEM economics.

Ultimately, this study offers a first step in quantifying utility risk under rising distributed generation adoption in a high-latitude, isolated system. The various compensation schemes and rates are briefly presented, along with both the barriers and motivators of distributed generation in Arctic and subarctic regions. This work presents the possible magnitudes of stress that can be expected based on varying adoption levels and compensation schemes.

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Abbreviations

The following abbreviations are used in this manuscript:

ACER	Agency for the Cooperation of Energy Regulators
AEA	Alaska Energy Authority
CEA	Chugach Electric Association
DER	Distributed Energy Resource
DSO	Distribution System Operator
FNSB	Fairbanks North Star Borough
GVEA	Golden Valley Electric Association
HB 164	Alaska State House Bill 164
HEA	Homer Electric Association
ITC	Investment Tax Credit
kWh	Kilowatt-hour

MEA	Matanuska Electric Association
NEM	Net Energy Metering
NB	Net Billing Compensation Rate Scheme
NM	Net Metering Compensation Rate Scheme
PPA	Power Purchase Agreement
RCA	Regulatory Commission of Alaska
TW	Terawatts

Appendix A

Appendix A.1. Equations

System Unit Price

$$\$_{PV}(t) = a \cdot e^{-b(t-t_0)} + c \quad (A1)$$

where

- $\$_{PV}(t)$ is the PV system unit price in year t (US\$/kW);
- t_0 is the base year for the regression;
- a is the initial exponential decay amplitude (US\$/kW);
- b is the decay rate (1/year), controlling how fast the price decreases;
- c is the asymptotic floor price of the system (US\$/kW);

System Operation and Maintenance Costs

$$C_T(t) = \begin{cases} C_{O\&M}(t), & t \neq 13 \\ C_{O\&M}(t) + C_I, & t = 13 \end{cases} \quad (A2)$$

where

- $C_T(t)$ is the consumer-generator's total cost in year t (US\$);
- $C_{O\&M}(t)$ is the operation and maintenance costs in year t (US\$);
- C_I is the inverter exchange cost (US\$).

Prosumer Cash Flows and ITC credits

$$CF(t) = \begin{cases} -C_{PV} \cdot (1 - ITC(t)), & t = 0 \\ B_T(t) - C_T(t), & t > 0 \end{cases} \quad (A3)$$

where

- $CF(t)$ is the consumer-generator's cash flow in year t (US\$);
- C_{PV} is the PV system installation cost (US\$);

and

- $ITC(t)$ is the applicable investment tax credit rate in year t (%), defined as:

$$ITC(t) = \begin{cases} 0.30, & \text{if } t + t_i \leq 2032 \\ 0.26, & \text{if } t + t_i = 2033 \\ 0.22, & \text{if } t + t_i = 2034 \\ 0.00, & \text{if } t + t_i \geq 2035 \end{cases}$$

when

- t_i is the initial year, for this study that is 2025.

Discounted Prosumer Cash Flows

$$DCF(t) = \frac{CF(t)}{(1 + CC)^t} \quad (A4)$$

where

- $DCF(t)$ is the discounted cash flow in year t (US\$);
- CC is the consumer-generator's cost of capital (%).

Potential Adopters Market & Forecast

$$N(t) = M(t) \cdot \frac{1 - e^{-(p+q)(t-t_D)}}{1 + \frac{q}{p}e^{-(p+q)(t-t_D)}} \quad (A5)$$

where

- $N(t)$ is the accumulated number of PV systems adopters in year t ;

and the following parameters are determined by non-linear regression using PV systems historical adoption data:

- p and q are the innovation and imitation coefficients as defined by the Bass model;
- t_D is the projection initial year.

Avoided Generation Benefits

$$E_I(t) = E_G(t) \cdot (1 - \xi) \quad (A6)$$

$$B_{E_I}(t) = E_I(t) \cdot V_{E_I}(t) \quad (A7)$$

where

- $E_I(t)$ is the energy injected by the PV systems in year t (MWh);
- $B_{E_I}(t)$ is the benefit referring to energy injected in the distribution network, in year t , by PV system (US\$);
- $V_{E_I}(t)$ is the valuation of energy injected by the PV system in year t (US\$/MWh);
- $E_G(t)$ must be converted (MWh).

Transmission and Distribution Loss Reduction

$$B_{R_D}(t) = B_{E_I}(t) \cdot \left(\frac{1}{1 - P_D} - 1 \right) \quad (A8)$$

$$B_{R_T}(t) = B_{E_I}(t) \cdot \left(\frac{1}{1 - P_T} - 1 \right) \quad (A9)$$

where

- $B_{R_D}(t)$ and $B_{R_T}(t)$ are the benefits due to the reduction in energy loss in distribution and transmission systems in year t (US\$);
- P_D and P_T is the average technical reduction in distribution and transmission system losses (%).

Transmission Expansion Reduction

$$B_{E_T}(t) = P_A(t) \cdot V_P(t) \quad (A10)$$

where

- $B_{E_T}(t)$ is the benefit referring to the avoided expansion in the transmission system in year t (US\$);
- $P_A(t)$ must be converted (MW);

- $V_P(t)$ is the value of the avoided expansion in year t (US\$/MW).

Lost Utility Revenue from Prosumer Savings

$$C_{RM}(t, i) = T_E(t) \cdot E_G(t - i) \cdot (1 - \xi) \quad (\text{A11})$$

where

- $C_{RM}(t, i)$ is the cost, in year t , related to the reduction of utilities' market, due to the PV systems installed in year i (US\$).

Compensation Paid by Utility

$$C_E(t) = E_I(t) \cdot V_{EC}(t) \quad (\text{A12})$$

where

- $C_E(t)$ is the cost referring to energy injected in the distribution network, in year t , by PV system (US\$);
- $V_{EC}(t)$ is the valuation at which the energy injected by the PV system, in year t , is credited to the consumer-generator (US\$/MWh).

Appendix A.2. Alaska PV Data

Table A1. Expected value, μ , and standard deviation of the average installed power of PV systems, $P_A(t)$, in kW for each individual Railbelt utility as well as a combined average. Based on data from [43–46].

Utility	Average Installed Power of PV Systems (kW)	
	μ	Std
CEA	4.51	0.90
GVEA	5.42	0.26
HEA	5.40	1.09
MEA	5.87	0.95
Combined Railbelt	5.42	0.65

Table A2. The theoretical maximum irradiance based on the air mass ratios in Anchorage & Fairbanks. Note: temperature, humidity, albedo, or other potentially impactful factors were not taken into account. Based on data from [37].

Location	Theoretical Maximum Irradiance (W/m ²)		
	21 December	20 March	21 June
Anchorage	280	841	980
Fairbanks	100	790	970

Table A3. Average values of the monthly solar irradiance (kWh/m²/day) in Juneau, Alaska based on data from [67].

Month	Average	Low	High
January	2.01	1.11	5.54
February	2.83	1.90	6.18
March	3.42	4.00	6.89
April	4.94	5.18	7.38
May	5.27	6.16	7.44

Table A3. Cont.

Month	Average	Low	High
June	5.16	6.21	7.39
July	5.92	5.68	6.72
August	5.66	4.92	7.06
September	5.01	3.58	7.46
October	3.36	2.22	6.44
November	1.87	1.36	5.87
December	1.76	1.45	4.93
Annual	3.93	3.65	6.61
March–September	4.84	4.74	7.10
October–February	2.12	1.46	5.63

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