Rooftop Photovoltaics and the Urban Heat Island in the Las Vegas Valley

Thermal Effects, Long-Term Degradation in Desert Environments, and the Policy Conflict Between Utility Revenue Protection and Urban Heat Mitigation

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Working draft — companion to the EV/UHI, Heat Pump, and Roof Color papers

March 2026

Abstract

This paper analyzes the interaction between rooftop photovoltaic (PV) systems and the urban heat island in the Las Vegas valley, extending the control-volume framework and roof heat budget developed in the companion papers on transport electrification, heat pump adoption, and roof color. Rooftop PV panels interact with the urban heat budget through a mechanism unique among roof surfaces: they absorb solar radiation like any dark surface but convert 18–22% of the incident energy to electricity that is physically removed from the local thermal budget. Simultaneously, the panel-to-roof standoff gap creates a ventilated shade structure that reduces heat transfer to the attic by approximately 38% (UCSD field measurements) to 49% (Shukla et al., New Mexico). The analysis quantifies four scenarios—dark asphalt, light tile, dark asphalt with PV, and the author's insulated double-deck design with PV—finding that PV on a dark asphalt roof reduces total atmospheric heat loading by 10–15% compared to the same roof without panels, but a light tile roof without PV still produces less local atmospheric heat than a dark roof with PV, because tile's high albedo (0.45) reflects more energy at the surface than PV's electricity conversion (21%) can extract. The optimal assembly—insulated double-deck with PV—minimizes both local heat loading and grid carbon simultaneously. The analysis then addresses two critical realities that the solar industry's marketing understates. First, PV degradation in the Las Vegas desert environment is substantially worse than warranty curves imply: the compound effects of glass micro-scratching from wind-borne sand, encapsulant yellowing from extreme UV exposure (UV Index 10–12 for five months annually), thermal cycling fatigue from 100°F+ daily surface temperature swings, and chronic dust soiling suggest that panels in Las Vegas are a 15–20 year investment producing 60–75% of rated output by year 15, not the 25–30 year asset at 85–90% output implied by industry warranties. Second, Nevada's net metering regulations—shaped by NV Energy (owned by Berkshire Hathaway Energy, a subsidiary of Warren Buffett's Berkshire Hathaway)—cap residential PV system sizing at 100% of annual consumption and compensate grid exports at only 75% of the retail rate, creating a policy environment that actively prevents homeowners from maximizing roof coverage with PV. This paper argues that this regulatory structure has an unquantified externality: the forgone UHI mitigation from roof area that could be shaded by panels the homeowner is willing to install but is legally prohibited from deploying. An international comparison with Germany's feed-in tariff model (which produced 1.6 million residential solar installations with no sizing cap) and Australia's net export schemes demonstrates that Nevada's approach is among the most restrictive in the developed world for a jurisdiction with among the highest solar resources.

Keywords: *photovoltaic, rooftop solar, urban heat island, Las Vegas, panel degradation, desert climate, net metering, NV Energy, Berkshire Hathaway, feed-in tariff, albedo, shading, atmospheric heat budget, policy*

1. Introduction

The companion papers in this series have progressively built a control-volume heat budget for the Las Vegas valley, quantifying the atmospheric heat contributions from the internal-combustion vehicle fleet (Brandys, 2026a), residential gas furnace heating (Brandys, 2026b), and residential roof surfaces (Brandys, 2026c). The roof color paper identified residential roofs as the largest single anthropogenic heat source in the residential sector, at approximately 5–6 GW peak atmospheric loading under the current roof stock distribution—exceeding the entire ICE fleet transport heat of 2.65 GW by a factor of two. That analysis examined passive roof surfaces: shingles and tiles of varying color and assembly type. This paper addresses the most thermodynamically complex roof modification in the valley: rooftop photovoltaic panels.

PV panels occupy a unique position in the urban energy balance. Unlike every other roof surface—which can only reflect or absorb solar radiation, converting all absorbed energy to heat—PV panels extract a fraction of the absorbed solar energy as electricity. This electricity is physically removed from the local heat budget: it either powers the home (displacing grid electricity) or is exported to the grid. No other roof surface can achieve this energy extraction. Simultaneously, the panel structure shades the roof deck beneath it and creates a ventilated air gap that reduces heat transfer to the attic. These two effects—electricity extraction and shading—make PV panels a potentially powerful UHI mitigation tool.

However, the interaction is more nuanced than the simple narrative of “solar panels cool your roof” suggests. PV panels are dark (albedo approximately 0.07), absorbing roughly 93% of incident solar radiation—more than even a dark asphalt shingle. The 78–82% of absorbed energy that is not converted to electricity becomes heat on the panel surface, which can exceed 150°F, radiating and convecting into the boundary layer from an elevated surface. Whether a PV-covered roof produces more or less total atmospheric heat than a light-colored roof without PV depends on the competing magnitudes of electricity extraction, panel surface heating, and roof deck shading—a calculation this paper undertakes.

The analysis further addresses two realities that are critical for honest assessment of PV’s role in the Las Vegas urban heat budget: the accelerated degradation of PV panels in the desert environment, and the regulatory constraints imposed by Nevada’s net metering structure on the extent to which homeowners can deploy PV on their available roof area. Both factors reduce the actual thermal benefit below the theoretical potential, and both have been understated in public discourse.

2. Photovoltaic Thermal Physics in the Urban Heat Budget

2.1. The PV Energy Budget

When solar radiation at intensity I (W/m²) strikes a PV panel, the energy is partitioned into three streams: (1) a small fraction is reflected (panel albedo approximately 0.07, so roughly 7% is reflected); (2) a fraction equal to the panel efficiency (18–22% for modern monocrystalline panels) is converted to direct-current electricity; and (3) the remainder (approximately 71–75%) is absorbed as heat by the panel. For a representative modern panel at 21% efficiency under 1,000 W/m² peak Las Vegas irradiance, the partition is approximately 70 W/m² reflected, 210 W/m² converted to electricity, and 720 W/m² converted to heat on the panel surface.

The electricity stream is the unique contribution of PV to the heat budget. These 210 W/m² are physically removed from the local atmosphere—they do not heat the roof, the attic, or the boundary layer. They either power the home (displacing grid draw) or are exported to the grid. The heat displaced at the power plant is outside the control volume, but the local energy removal is real and measurable.

For comparison, a dark asphalt shingle (albedo 0.08) absorbs 920 W/m² and converts 100% of it to heat—no electricity extraction. A light tile (albedo 0.45) absorbs 550 W/m², again all as heat. The PV panel absorbs 930 W/m² (more than the dark shingle) but removes 210 W/m² as electricity, leaving 720 W/m² as local heat—less than the dark shingle (920 W/m²) but substantially more than the light tile (550 W/m²). This comparison is central to the policy question of PV versus cool roofs.

2.2. The Shading Effect

PV panels mounted on residential roofs in Las Vegas are typically installed on rail systems with a 3–6 inch standoff above the roof surface, creating a ventilated air gap between the panel underside and the shingle or tile surface. This gap functions as a shade structure with passive ventilation: the panel blocks direct solar radiation from reaching the roof deck, and convective airflow through the gap carries heat away before it can conduct through the deck to the attic.

The most rigorous field measurement of this effect was conducted by Dominguez, Kleissl, and colleagues at UC San Diego, who used thermal infrared imagery and heat flux modeling on a building partially covered by PV panels. Their results showed that daytime ceiling temperatures under the PV arrays were up to 2.5 K (4.5°F) cooler than under the exposed roof, and that the PV array reduced the annual cooling load through the covered roof section by 5.9 kWh/m², or 38%. A separate study by Shukla et al. in New Mexico found an even larger effect: daily peak heat flow through the attic ceiling was almost halved (49% reduction) under PV panels, with roof tile temperatures under the panels up to 13°C (23°F) lower than the exposed roof.

The shading benefit is analogous to the ventilated air gap under batten-mounted concrete tile (analyzed in the companion roof color paper), but with a larger standoff height and therefore stronger convective ventilation. The PV shading effect is additive to whatever roof surface lies beneath—panels over a dark shingle produce a larger absolute temperature reduction than panels over a light tile, because the dark shingle has more heat to mitigate.

2.3. Net Heat to Atmosphere: PV vs. Cool Roof Comparison

The central question for urban heat policy is whether PV panels produce more or less total atmospheric heat than alternative roof surfaces. The per-square-meter comparison at peak Las Vegas conditions (1,000 W/m²):

Roof Surface	Albedo	Elec (W/m²)	Heat (W/m²)	vs. Dark asphalt	Rank (heat)
Dark asphalt shingle	0.08	—	920	Baseline	Worst
PV panel (21% eff.)	0.07	210	**720**	−22%	3rd
Medium tile (ventilated)	0.32	—	680	−26%	4th
Light asphalt shingle	0.30	—	700	−24%	3rd (tie)
Light tile (ventilated)	0.45	—	**550**	−40%	Best passive
Insulated deck + PV	0.35*	210*	**~420**	**−54%**	**Best overall**

*Table 1. Per-square-meter heat to atmosphere at 1,000 W/m². PV panel comparison is for covered area only; exposed roof area contributes additional heat at the underlying surface's albedo. *Insulated deck values reflect weighted average of PV-covered and exposed light-shingle areas at 55% PV coverage.*

Key finding: A PV panel produces less local atmospheric heat than a dark asphalt shingle (720 vs. 920 W/m²) but substantially more than a light tile (720 vs. 550 W/m²). For the local UHI, a light tile roof is superior to a PV-covered dark roof. For the global energy balance, PV is superior because the electricity displaces fossil generation. These are different objectives that require different policy tools—cool-roof ordinances for UHI mitigation, PV incentives for decarbonization. The optimal solution is both: the insulated double-deck + PV assembly that minimizes local heat AND maximizes electricity generation.

3. PV Degradation in Desert Environments

3.1. The Industry Narrative vs. Desert Reality

The solar industry markets residential PV systems as 25–30 year investments with manufacturers warranting 90% output at 10 years and 80% at 25 years, implying a degradation rate of approximately 0.5% per year. This warranty assumption is derived primarily from testing under standard conditions (IEC 61215 and IEC 61730), which were developed for moderate climates and do not fully represent the stresses of hot desert environments. A Sandia National Laboratory study of high-efficiency PV modules found annual degradation rates as high as 2%, and multiple field studies in desert and tropical locations have measured rates of 1.2% to 1.8% per year—two to four times the industry standard assumption.

Las Vegas presents a particularly aggressive environment for PV panels due to the simultaneous presence of five degradation mechanisms that compound over the panel's service life. Each mechanism alone might be manageable; together, they produce cumulative damage that the standard warranty curve understates.

3.2. Five Compounding Degradation Mechanisms

Mechanism 1: Dust soiling (reversible but chronic). Desert dust reduces output by 5–25% depending on cleaning frequency. Las Vegas-specific data from local installers indicates fine desert sand can block up to 15% of incoming sunlight between quarterly cleanings. This is recoverable with washing, but quarterly professional cleaning costs $150–300/year—an ongoing expense that erodes the economic return. And the cleaning process itself introduces the next problem.

Mechanism 2: Glass micro-scratching (permanent, cumulative). A five-year field coupon study across desert sites including Mesa, Arizona (climatically similar to Las Vegas) found that both wind-borne sand particles and the cleaning process itself cause progressive abrasion damage to the glass surface and any anti-reflective or anti-soiling coatings. Windborne sand scratches surfaces and gathers around seals, creating micro-gaps that weaken insulation, with performance declining steadily beyond the reach of routine cleaning. After 10–15 years, the glass develops a cumulative haze from micro-scratches that permanently reduces transmittance. This damage cannot be cleaned away because it is in the glass itself.

Mechanism 3: Encapsulant yellowing and browning (permanent, UV-driven). The EVA (ethylene-vinyl acetate) encapsulant that protects the silicon cells degrades from UV exposure and heat, turning progressively yellow then brown, reducing light transmission to the cells beneath. NREL and DOE field studies have consistently identified encapsulant discoloration as the most common degradation mode in PV modules, particularly in older systems and hotter climates. Las Vegas receives UV Index 10–12 for five continuous months (May–September), with panel surface temperatures routinely exceeding 150°F—a combination that accelerates EVA degradation beyond the rates assumed in standard IEC testing, which was designed for moderate climates. Standard IEC test protocols underrepresent these desert stresses.

Mechanism 4: Cell-level electrical degradation (permanent). Silicon solar cells undergo progressive electrical degradation from light-induced degradation (LID), potential-induced degradation (PID), and metallization corrosion. These mechanisms are temperature-dependent and UV-dependent, both of which are extreme in Las Vegas. At the 1.0%/year rate that field studies in desert environments support (versus the 0.5% industry assumption), a panel retains

only 78% of rated output at year 25. At the 1.5% rate reported in some desert studies, output falls to 68%—well below the 80% warranty threshold.

Mechanism 5: Thermal cycling fatigue (permanent, mechanical). Las Vegas has one of the largest diurnal temperature swings of any major U.S. city during summer. Roof surfaces go from approximately 60°F at dawn to 170°F at midday and back, daily, for six months. This repeated thermal expansion and contraction fatigues solder joints, creates microcracks in silicon cells, and stresses electrical interconnects. The damage is invisible but cumulative, and it compounds with the other mechanisms.

3.3. Compound Degradation Curve for Las Vegas

Stacking these five mechanisms over the panel's service life produces a compound degradation profile substantially steeper than the industry warranty curve:

Year	Industry warranty	Desert field data	With soiling	With glass haze	Compound est.
New	100%	100%	100%	100%	100%
Year 1	97.5%	97%	90–95%*	97%	87–92%
Year 5	95%	92–95%	85–90%*	93–95%	78–85%
Year 10	90%	85–90%	80–85%*	88–92%	68–78%
Year 15	87%	78–85%	75–80%*	83–88%	**60–75%**
Year 20	83%	70–80%	70–75%*	78–85%	**52–68%**
Year 25	80%	63–75%	60–70%*	73–80%	**45–62%**

Table 2. Estimated PV output as percentage of rated capacity over time. Industry warranty assumes 0.5%/yr degradation. Desert field data assumes 1.0–1.5%/yr. Soiling column (*) assumes quarterly cleaning; between-cleaning average output. Glass haze is permanent cumulative damage. Compound estimate combines all five mechanisms. Ranges reflect variation in panel quality, maintenance, and local exposure.

The practical implication: a 15-year-old PV system in Las Vegas that has been cleaned quarterly is likely producing 60–75% of its original rated output, not the 87% the industry warranty curve implies. By year 20–25, the panel is functioning increasingly as a shade structure—blocking sunlight from the roof deck but converting a diminishing fraction to electricity. The heat that the degraded panel absorbs but cannot convert becomes additional thermal radiation into the boundary layer, gradually shifting the panel's role from "electricity generator + shade" toward "dark parasol."

3.4. Practical Lifespan Assessment

Based on the compound degradation analysis, PV panels in the Las Vegas desert environment should be treated as a 15–20 year investment, not the 25–30 year asset implied by industry marketing. This has three implications for the urban heat budget analysis: (1) the electricity extraction benefit declines over time, reducing the thermal advantage of PV over passive cool surfaces; (2) homeowners should plan for panel replacement coordinated with roof replacement at the 15–20 year mark; and (3) the heat budget model should use a time-averaged efficiency (approximately 75–85% of rated over the practical lifespan) rather than new-panel efficiency for fleet-scale calculations.

4. Valley-Scale PV and the Atmospheric Heat Budget

4.1. Current PV Penetration

Precise data on the number of Clark County single-family homes with rooftop PV installations is not available from a single public source. NV Energy tracks net metering interconnections, and the PUC docket records would contain cumulative counts, but these data have not been compiled for public access. Nevada had approximately 32,000 grandfathered net metering customers when the Tier 1 program filled in 2018, and the market has continued growing through Tiers 2, 3, and 4. Based on cumulative tier capacity and typical system sizes, a reasonable estimate is approximately 105,000 rooftop solar customers in the Las Vegas valley as of 2024, representing roughly 18% of the single-family housing stock, according to an NV Energy federal regulatory filing. This figure is used as the central estimate throughout this analysis.

4.2. Net Heat Reduction from Current PV Fleet

At 18% penetration (105,000 homes) with an average of 55% roof coverage and 21% panel efficiency (degraded by fleet-average aging to approximately 17% effective), the PV fleet removes approximately 0.5–0.7 GW of electricity from the local heat budget at peak solar conditions. The shading effect on the underlying roof reduces an additional 0.2–0.4 GW of heat that would otherwise enter through attic pathways. The combined effect is a net heat reduction of approximately 0.7–1.1 GW compared to the same homes without PV—roughly 15–20% of a single-home's heat loading, aggregated across the PV fleet.

For context, this is comparable in magnitude to the avoided warming from converting approximately one-quarter of the gas furnace fleet to heat pumps (the companion heat pump paper estimated 2.0 GW of total extraction for the full fleet). The PV thermal benefit is a meaningful but secondary contributor to the overall heat budget, operating during daytime hours when the convective boundary layer is deep (1,000+ feet), diluting the temperature perturbation. The thermal storage released after sunset from PV-covered roofs is reduced relative to bare dark roofs, contributing a modest benefit during the nocturnal hours when UHI sensitivity is highest.

4.3. Scenario Analysis: What If PV Were Maximized?

If all 580,000 single-family homes were equipped with PV at 55% roof coverage and modern 21% efficiency (new panels), the fleet would remove approximately 4.0–4.5 GW as electricity at peak conditions—comparable to the entire current ICE fleet transport heat of 2.65 GW. The combined scenario of light-colored roof surfaces on exposed areas plus maximum PV coverage on the remainder would produce the lowest total atmospheric heat loading achievable through roof modifications alone: approximately 2.5–3.0 GW total, versus the current estimated 5.4 GW. However, Nevada's regulatory structure prevents this scenario from being realized, as discussed in Section 5.

5. The Policy Conflict: Utility Revenue Protection vs. Urban Heat Mitigation

5.1. Nevada's Net Metering Structure

Nevada's net metering regulations, implemented by the Public Utilities Commission of Nevada (PUCN) at the direction of the state legislature and in negotiation with NV Energy, impose two constraints that directly limit the extent of residential PV deployment:

The 100% sizing cap: By Nevada law, net metering systems cannot be designed to produce more than 100% of the customer's annual energy requirements. NV Energy determines the maximum system size by examining the customer's highest 12-month energy usage over a 24-month period. A homeowner with abundant roof area who wishes to install additional panels beyond this cap is prohibited from doing so under the net metering framework. The only exception is if the homeowner can document a planned increase in electricity consumption (such as an EV charger), supported by a licensed engineer's calculation.

The declining export rate: When a PV system generates more electricity than the home consumes at any given moment, the excess is exported to the NV Energy grid. The compensation for this export has declined through four tiers: Tier 1 paid 95% of the retail rate (filled at 80 MW in August 2018); Tier 2 paid 88% (filled June 2019); Tier 3 paid 81% (filled June 2020); and the current Tier 4 pays 75% of the retail rate, with no further reduction scheduled. New solar customers in 2026 receive 75 cents on the dollar for every kWh they contribute to the grid.

5.2. The Berkshire Hathaway Context

NV Energy is owned by Berkshire Hathaway Energy, a subsidiary of Warren Buffett's Berkshire Hathaway. This ownership structure is relevant because the regulatory proceedings that produced Nevada's net metering structure were shaped by NV Energy's advocacy before the PUCN. The 2015 decision that retroactively reduced net metering rates for existing solar customers—causing SolarCity, Vivint, and SunRun to withdraw from the Nevada market entirely—was initiated at NV Energy's request. While the legislature partially reversed the 2015 decision with AB 405 in 2017, the resulting tiered structure still reduces the economic return on residential PV compared to full retail net metering, and the 100% sizing cap remains in place.

The economic logic from NV Energy's perspective is straightforward: every kWh a homeowner generates is a kWh NV Energy does not sell, and every kWh exported at 75% of retail is a kWh NV Energy must accept at a price it considers above avoided cost. The utility's financial interest is to limit the quantity of distributed generation to what can be absorbed without materially reducing its revenue from volumetric electricity sales. The PUCN has explicitly created a "regulatory asset"—an accounting mechanism that allows NV Energy to track revenue shortfalls attributable to net metering and potentially recover them in future rate cases from all ratepayers.

5.3. The Forgone Heat Mitigation Externality

The 100% sizing cap has an unquantified externality: the forgone UHI mitigation from roof area that could be covered by PV panels but is legally prohibited. Consider a representative Las Vegas home with 1,500 sq ft of available south-facing roof area. If the home's annual consumption dictates a system of 8 kW (approximately 825 sq ft of panel area at current panel wattage), the remaining 675 sq ft of available roof is left as bare shingles. If those shingles are dark asphalt (the typical underlying roof on older homes), that 675 sq ft generates approximately

920 W/m² of pure waste heat—no electricity extraction, no grid contribution, no benefit to anyone.

Had the homeowner been permitted to install panels on that additional 675 sq ft, the heat reduction would be approximately 200 W/m² of electricity extracted plus the shading benefit—a net heat savings of approximately 13 kW per home during peak conditions. Aggregated across the approximately 105,000 homes with PV, the forgone coverage represents roughly 58 million sq ft of roof area that could be generating electricity and providing shade but is instead producing unmitigated waste heat. The forgone heat reduction is on the order of 0.3–0.5 GW at peak—modest in the context of the 5.4 GW total, but nontrivial and entirely avoidable through a policy change that costs nothing.

The homeowner in this scenario has already invested $20,000–30,000 in a solar installation, has available roof area, and is willing to install additional panels. The only barrier is a regulatory cap designed to protect the utility's volumetric revenue. The external cost—additional heat loading on the urban airshed borne by all valley residents—is not considered in the regulatory calculus.

5.4. International Comparison

Nevada's approach to distributed solar is among the most restrictive in the developed world for a jurisdiction with world-class solar resources. The comparison with other regulatory models is instructive:

Jurisdiction	Sizing cap	Export rate	Residential PV result	Key distinction
Nevada (NV Energy)	100% of use	75% retail	10–18% penetration	Utility revenue protection model
California (NEM 3.0)	No % cap	~25% retail avg	~25% penetration	Dramatic 2023 export rate cut
Colorado (Xcel)	120% of use	~100% retail	~15% penetration	Allows modest oversizing
Germany (FiT)	No cap	Fixed FiT rate	1.6M installations	400% local production achieved
Australia (net FiT)	Varies by network	Market rate	>30% penetration	Competitive retailer market

Table 3. International comparison of residential PV regulatory frameworks. Nevada's combination of 100% sizing cap and 75% export rate is among the most restrictive in the developed world.

Germany's feed-in tariff, enacted in 2000, represented the opposite regulatory philosophy: it guaranteed above-market prices for 20-year contracts, imposed no sizing cap relative to consumption, and required utilities to purchase and connect all eligible renewable energy. The result was 1.6 million residential solar installations in a country of fewer than 40 million households, with some communities producing 400% of their local energy needs. Three-quarters of global solar PV deployment has been associated with feed-in tariff policies. The German model demonstrated that when regulatory barriers are removed and economic incentives aligned, residential distributed generation can scale to become a dominant energy source.

Australia operates net feed-in tariff schemes where homeowners are compensated for all excess exports at rates set by competitive energy retailers. The Australian market has achieved residential PV penetration exceeding 30% in some states, with export limits set by local network

operators based on grid capacity rather than consumption-matching rules. The result is substantially higher roof coverage ratios than Nevada achieves.

5.5. What Rooftop PV Power Is Actually Worth to the Utility

The debate over fair compensation for rooftop PV exports is typically framed around a single number: what percentage of the retail rate should the homeowner receive? This framing obscures the real question, which is: how much does the utility actually save when a homeowner generates a kWh at the point of consumption instead of the utility generating it at a remote power plant? The answer has six components, not one, and varies dramatically by time of day and season.

The six avoided cost components are: (1) fuel and variable operations cost for the marginal generating unit (3–5¢/kWh for baseload combined-cycle gas, 5–8¢/kWh for peaking turbines at current gas prices); (2) transmission and distribution costs avoided because the power is generated and consumed at the same location (2–4¢/kWh depending on congestion and line losses); (3) capacity value—the cost of the peaking generation capacity that does not need to be built or maintained (1.5–2.5¢/kWh, discussed in detail in Section 5.6); (4) ancillary services including frequency regulation and voltage support (0.2–0.8¢/kWh); (5) the UHI/AC co-benefit quantified in the companion papers—reduced community-wide air conditioning demand from lower atmospheric heat loading (0.5–1.2¢/kWh during summer); and (6) environmental externalities including CO_2 emissions, water consumption for cooling, and land use (0.5–1.5¢/kWh).

During summer peak hours (1–7 PM, June through September), when PV output is near maximum and the grid is running expensive peaking turbines, the total avoided cost is approximately 14–20¢/kWh—at or above the full retail rate. During shoulder hours (8 AM–1 PM), when baseload combined-cycle plants are the marginal generator, the avoided cost is approximately 10–14¢/kWh. During spring and fall midday, when demand is moderate, the avoided cost drops to approximately 8–11¢/kWh. The PV-production-hours weighted average across all seasons is approximately 12–16¢/kWh—right at the retail rate. NV Energy's Tier 4 export credit of 10.5¢/kWh (75% of 14¢) falls below the full avoided cost during the highest-value hours and roughly at the avoided cost during the lowest-value hours. The flat rate structure systematically underpays during peak hours and overpays during low-value hours, destroying the price signal that would encourage homeowners to orient panels west, install batteries, and shift exports to the hours when the grid needs them most.

5.6. The Demand Growth Reversal and the Avoided Power Plant

The single largest avoided cost component—and the one most consistently excluded from regulatory proceedings—is the capital cost of the power plant that does not need to be built. Understanding why this component was historically excluded, and why it can no longer be excluded, requires a brief history of U.S. electricity demand.

From 1950 through 2005, U.S. electricity demand grew steadily at 2–10% per year. Utilities operated on a straightforward business model: forecast rising demand, build new power plants, add the capital cost to the rate base, and earn a regulated return on the investment. By 2005, the U.S. was generating approximately 4,000 TWh annually. Then demand growth stopped. The combination of LED lighting (which reduced lighting electricity consumption by roughly 80% per fixture as the installed base turned over), efficient HVAC systems, appliance efficiency standards, and the structural economic shift away from energy-intensive manufacturing flattened demand. U.S. electricity sales peaked in 2007 and had not meaningfully recovered by

2020. For 15 years, utilities built almost no new baseload generation. During this era, it was at least arguable that rooftop PV displaced only marginal fuel costs, because no new capacity was needed regardless.

That argument ended abruptly in 2024. The explosive growth of artificial intelligence data centers has broken the 15-year demand plateau. A January 2026 report by Bloom Energy projects that U.S. data center electricity demand will nearly double from 80 GW to 150 GW between 2025 and 2028—equivalent to adding a country the size of Spain's entire electricity demand in three years. Meta received approval for a 700 MW on-site natural gas plant in Ohio. Google committed $75 billion to data center construction in 2025, more than doubling the prior year. Microsoft signed a 20-year agreement to restart the Three Mile Island nuclear plant. U.S. utilities requested $31 billion in rate hikes in 2025 alone, with data center-driven demand cited as a primary driver. The era of building power plants is back.

Critically, the cost of building those plants has escalated dramatically. A GridLab analysis found that new combined-cycle gas turbine construction costs are now regularly exceeding $2,000/kW, up from $875/kW just a few years earlier—a near-tripling. Combustion turbine (peaker) plants have risen to $728–$1,544/kW. Even acquiring existing gas plants has become expensive, with transaction prices rising by approximately $40 million per year since 2020, driven by data center demand. A single 400 MW combined-cycle plant now costs approximately $800 million, requires 5+ years to permit and construct, consumes millions of gallons of cooling water annually, emits approximately 1.5 million metric tons of CO_2 per year, and requires new transmission lines to deliver its power to customers.

The alternative: approximately 17,000 homes with rooftop PV (at 8 kW each, 30% capacity factor) provide the equivalent average generation of that 400 MW plant. Those systems are built in months, not years. They are funded by homeowners, not ratepayers. They consume zero water. They emit zero CO_2. They deliver power at the point of consumption with zero transmission losses. And they shade the roof, reducing the home's AC load and the urban heat island simultaneously. When the capital recovery cost of the avoided plant is amortized over its kWh output and added to the fuel, T&D, ancillary, UHI, and environmental components, the total avoided cost during PV production hours rises to approximately 12–16¢/kWh—at or above the full retail rate. NV Energy's Tier 4 export credit of 10.5¢/kWh captures a margin of approximately 30–40% of the true avoided cost on every kWh the homeowner exports, while simultaneously telling regulators that solar customers are being "subsidized" by non-solar ratepayers.

5.7. The AI Data Center Environmental Contradiction

The AI-driven demand surge has created a stark environmental contradiction. Google, Microsoft, Amazon, and Meta have all made public commitments to carbon neutrality or net-zero operations. Yet all four companies' absolute emissions rose in their 2024 sustainability reports as data center construction outpaced renewable energy procurement. Several companies have quietly walked back near-term climate commitments. Meta's 700 MW gas plant in Ohio will emit approximately 2.5 million metric tons of CO_2 per year. Approximately 60% of the electricity powering U.S. data centers still comes from fossil fuels. The International Energy Agency projects that global data center electricity demand will grow from 460 TWh in 2024 to over 1,000 TWh by 2030, with natural gas and coal meeting roughly half of the incremental demand.

This global context makes the local policy question more urgent, not less. Every rooftop kWh that enters the NV Energy grid is a kWh that does not need to come from a new gas plant—whether that plant is built for local demand growth, for data center demand, or for export through regional transmission. The economic incentive structure should encourage distributed

generation to maximize grid contribution, not cap it at 100% of household consumption. Germany's feed-in tariff demonstrated that when regulatory barriers are removed and homeowners are paid the full avoided cost of generation, distributed solar can scale to become a dominant energy source. The U.S. approach—paying homeowners less than avoided cost while simultaneously permitting utilities to build new gas plants and pass those capital costs to all ratepayers—is economically incoherent and environmentally destructive. Ratepayers pay more, emissions increase, and the urban heat island worsens.

5.8. Policy Recommendation

The analysis in this paper argues for two policy changes that would align Nevada's regulatory framework with both decarbonization and UHI mitigation objectives:

1. Remove the 100% sizing cap for net metering systems, or at minimum raise it to 120–150% of annual consumption (as Colorado's Xcel Energy allows). This would permit homeowners with available roof area to maximize PV coverage, providing additional grid electricity, shading more roof area, and reducing the atmospheric heat externality. The cost to NV Energy is the incremental export compensation at the already-reduced 75% rate—a cost that is partially offset by the avoided need for peaking generation capacity during the summer afternoon hours when rooftop PV output is highest.

2. Credit the UHI mitigation co-benefit of rooftop PV in the regulatory calculus. The PUCN's current framework evaluates net metering solely through the lens of utility cost recovery. It does not account for the external benefits of reduced urban heat loading—lower community-wide AC demand, reduced heat-related health impacts, and ecological benefits for native desert species dependent on nighttime thermal recovery (as documented in the companion heat pump and chill-hour papers). Incorporating these externalities into the benefit-cost analysis used by the PUCN to set net metering terms would shift the regulatory balance toward greater PV deployment.

5.9. Plug-In Balcony Solar: Bypassing the Utility Gatekeeping Problem

The policy constraints documented in the preceding sections—the 100% sizing cap, the 75% export rate, the interconnection requirements, the utility-controlled regulatory process—apply to conventional rooftop solar systems. A parallel technology development, already deployed at massive scale internationally, bypasses these constraints entirely: plug-in balcony solar, known in Germany as Balkonkraftwerk.

A plug-in solar system consists of one or two standard PV panels (typically 400–800 W total), a microinverter with built-in anti-islanding safety protection, and a standard electrical cord that plugs into a household wall outlet. The system feeds electricity directly into the home's internal wiring, reducing what the occupant draws from the grid. No electrician is required. No roof penetrations are made. No utility interconnection agreement is needed. The system can be hung from a balcony railing, propped against a south-facing wall, placed on a patio, or set up in a backyard. It moves with the occupant—a renter can take it to their next apartment. The total cost is $300–$600 for a basic system, or up to $1,000–$1,500 with an integrated battery for evening use. At Las Vegas solar irradiance, an 800 W balcony system would produce approximately 1,200–1,400 kWh per year—roughly $170–$200 in avoided electricity purchases at 14¢/kWh—yielding a payback period of approximately 2–3 years.

Germany has led this revolution, and the scale of its success deserves detailed examination because it demonstrates what is possible when regulatory barriers are removed. Balcony solar technology emerged in Germany around 2014–2015 as a niche product, but remained marginal until the government enacted the first dedicated technical regulations in 2019, allowing plug-in solar devices to use standard household electrical plugs and feed directly into the grid. Adoption accelerated during the COVID-19 pandemic (2020–2021) as people undertook home improvement projects, and then surged after Russia's 2022 invasion of Ukraine sent German electricity prices to record highs—households began buying anything that could reduce their energy bills. Between 140,000 and 190,000 units were sold in 2021; more than 800,000 were installed in 2024 alone, more than doubling the prior year and representing a tenfold increase over 2022. As of mid-2025, more than one million plug-in solar systems were officially registered with the German Federal Network Agency (Bundesnetzagentur), with the actual installed base estimated at 3–4 million units when unregistered systems are included. Between January and April 2025 alone, approximately 135,000 new systems were installed, and approximately half a million are now being added per year.

Three policy decisions drove this adoption. First, the German government eliminated the 19% value-added tax (VAT) on all solar equipment, making balcony kits effectively tax-free at the point of purchase. Second, the parliament wrote the right to plug-in solar into both the Mietrecht (rental contract law) and the Wohnungseigentumsgesetz (condominium law): renters have a legal right to install balcony solar, landlords must grant permission, and condominium associations cannot block individual owners from installing systems on their own balconies. Third, city and state governments layered generous subsidies on top of the federal VAT exemption. Berlin's SolarPLUS program provides up to €500 per system; by April 2024, over 7,700 grants had been approved. Frankfurt covers 50% of system cost. The German state of Mecklenburg-Vorpommern offers up to €500 per household. As a result, out-of-pocket costs can be remarkably low: one Berlin resident purchased an 800 W system for just €80 ($87) after receiving a €250 city subsidy.

Without subsidies, balcony solar kits in Germany are sold at supermarkets and hardware stores at prices that Americans would find astonishing. Lidl, Aldi, Amazon, and IKEA all sell complete plug-in kits. Prices range from approximately €200 ($218) for a single small panel to €500–€700

($545–$765) for a standard two-panel 800 W kit with microinverter and mounting hardware, up to €2,700 ($2,950) for premium kits with integrated battery storage. Lidl alone installs approximately half a million kits per year across its European operations and is now preparing to bring plug-in solar to UK stores following the British government's March 2026 announcement that it will legalize the technology. The German market for balcony PV microinverters is estimated at $3.2 billion and is projected to exceed $8 billion within four years. Systems are limited to 800 W inverter output and 2,000 W of panel capacity, use standard Schuko household plugs, and require only a simple online registration with the Marktstammdatenregister (market master data registry). The microinverters are certified to VDE safety standards (VDE-AR-N 4105) and include automatic anti-islanding shutdown if the grid fails or the plug is disconnected, preventing any risk of backfeed to utility workers. In December 2025, the VDE published a dedicated national standard for plug-in PV systems (DIN VDE V 0126-95), making Germany the first large country with a formal, purpose-built safety standard for the technology.

The common objection that plug-in solar only works in Europe because of 230 V power systems is incorrect. The safety constraint is current, not voltage. At 800 W and 230 V, the system draws approximately 3.5 amps—well within any household circuit's capacity. At U.S. 120 V, the same 800 W draws approximately 6.7 amps, still comfortably within a standard 15 A or 20 A household circuit. The microinverter's anti-islanding protection functions identically regardless of voltage. The barrier to plug-in solar in the United States has never been electrical safety—it has been regulatory: utilities require interconnection agreements for any device that feeds power into the grid, treating a 600 W balcony panel identically to a 10,000 W rooftop array.

That regulatory barrier is now falling rapidly in the United States. In March 2025, Utah became the first state to pass explicit plug-in solar legislation (House Bill 340), carving out an exemption from interconnection requirements for portable solar generation devices up to 1,200 W, unanimously passed by the legislature and signed by Republican Governor Spencer Cox. In March 2026, Virginia became the second state, passing its law by a unanimous 96–0 vote. As of March 2026, legislators in 30 states and Washington, D.C., have introduced similar bills, including California (SB 868, the Plug and Play Solar Act), New York, Illinois, New Jersey, New Hampshire, Vermont, Maine, Pennsylvania, and others. The movement is genuinely bipartisan—Utah and Virginia represent opposite ends of the political spectrum, and bills have been introduced in both deep-red and deep-blue states. UL Solutions launched the UL 3700 certification standard in January 2026 to provide a nationally recognized safety testing framework for plug-in solar devices, addressing the primary objection that utilities had raised against permissionless installation.

Nevada does not yet have a plug-in solar law. This paper recommends that the Nevada legislature introduce and pass legislation modeled on Utah's HB 340, exempting plug-in solar devices up to 1,200 W from interconnection agreements, utility approval, and permitting requirements, provided the device carries UL 3700 certification or equivalent safety certification. The case for Nevada is stronger than for any other state: Clark County has 201,000+ apartment units whose residents are entirely excluded from rooftop solar, Las Vegas has the highest solar irradiance of any major U.S. city, and NV Energy's retail rate of 14¢/kWh provides a 2–3 year payback on a $300–$600 investment. Plug-in solar would extend solar access to the approximately 70% of Las Vegas residents who currently cannot participate in rooftop solar because they rent, live in apartments, have unsuitable roofs, or cannot afford a $20,000+ rooftop system. Each plug-in system also provides a modest UHI co-benefit by reducing grid demand during peak hours, and the aggregate effect of widespread adoption across the valley's apartment stock could be meaningful.

6. The Optimal Roof Assembly for Las Vegas

The analyses in this paper and the companion roof color paper converge on a clear optimal design for residential roofs in the Las Vegas valley. The assembly that minimizes local atmospheric heat loading while maximizing electricity generation and minimizing AC energy consumption is:

Layer 1 (top): PV panels on rail mounts with 4–6 inch standoff, covering the maximum available south- and west-facing roof area. Even under the current 100% sizing cap, this provides electricity generation plus shading of the highest-solar-exposure roof sections.

Layer 2: Light-colored shingles (white on rear slopes not visible from street, light tan on front slopes for aesthetic compatibility) on all exposed (non-PV-covered) roof area. This maximizes albedo on the portions of the roof that the panels don't shade.

Layer 3: Second plywood deck (1/2 inch).

Layer 4: 2 inches of polyisocyanurate rigid foam insulation (R-12), installed as commercially available nailbase panels (Atlas ACFoam, GAF ThermaCAL, or equivalent) or as field-assembled isofoam boards over the existing deck.

Layer 5 (bottom): Original roof deck (existing plywood sheathing).

This assembly, as installed at the author's two Las Vegas residences, reduces attic temperature to within 5°F of ambient (eliminating attic venting heat discharge and ceiling heat gain), provides R-50+ total ceiling-to-exterior thermal resistance, generates electricity at the maximum rate the panels and regulations allow, and reflects maximum solar energy from all exposed surfaces. It is the thermodynamic optimum for both the homeowner and the urban airshed.

7. Limitations

The PV penetration rate of 15% is an estimate; NV Energy interconnection data would provide a precise count. The compound degradation curve in Table 2 is assembled from published studies in various desert climates; Las Vegas-specific long-term field data on panel degradation would strengthen the analysis. The forgone heat mitigation calculation assumes homeowners with PV would cover the maximum available roof area if permitted; actual behavior would depend on economics, aesthetics, and structural capacity. The international comparison focuses on regulatory framework differences; solar resource, electricity market structure, and political economy factors also influence PV penetration rates. The heat budget calculations use the same control-volume simplifications as the companion papers.

8. Conclusion

Rooftop PV panels occupy a unique and complex position in the Las Vegas urban heat budget. They are the only roof surface that can extract energy from the solar radiation they absorb, physically removing 18–22% of incident solar energy from the local thermal budget as electricity. This extraction, combined with the shading of the underlying roof deck, makes PV a net heat reducer relative to the bare dark shingle roof it typically covers. However, PV panels are not a cool-roof substitute: a light-colored tile roof without PV produces less local atmospheric heat than a dark roof with PV, because tile's high albedo reflects more energy at the surface than PV's electricity conversion can extract. The optimal assembly—the insulated

double-deck with PV documented in this paper—is the only configuration that minimizes local heat loading AND maximizes electricity generation simultaneously.

The PV degradation analysis reveals that panels in the Las Vegas desert environment face five compounding damage mechanisms—dust soiling, glass micro-scratching, encapsulant yellowing, cell-level electrical degradation, and thermal cycling fatigue—that together produce a steeper performance decline than the industry's 0.5%/year warranty assumption. A realistic assessment suggests PV panels in Las Vegas are a 15–20 year investment producing 60–75% of rated output by mid-life, not the 25–30 year, 85–90% asset implied by industry marketing. This degradation progressively shifts the panel's role from electricity generator toward passive shade structure—still providing UHI mitigation benefit but with diminishing electricity extraction.

Nevada's net metering structure—a 100% sizing cap and 75% export rate, shaped by NV Energy (Berkshire Hathaway Energy) advocacy before the PUC—actively prevents homeowners from maximizing PV coverage on available roof area. This creates an unquantified externality: forgone UHI mitigation from roof area that could be shaded by panels the homeowner is willing to install but is prohibited from deploying. An international comparison with Germany (no cap, 1.6 million installations) and Australia (>30% penetration) demonstrates that Nevada's approach is among the most restrictive in the developed world for a jurisdiction with among the highest solar resources.

8.1. What Homeowners Should Be Paid: The Full Economic Case

The central policy question raised by this analysis is: what should a Las Vegas homeowner be paid for each kWh of rooftop PV electricity? The answer requires accounting for two sides of the equation that are consistently presented separately in regulatory proceedings but must be considered together: the full value of the benefits the homeowner's generation provides to the utility and the community, and the full cost the homeowner actually bears to provide it.

On the benefit side, the full avoided cost stack developed in Sections 5.5 and 5.6, weighted across PV production hours and including the capital recovery of avoided power plant construction, yields an estimated 12–16¢/kWh during average solar production hours, rising to 16–20¢/kWh during summer peak. However, this stack still omits several quantifiable benefits that belong in a complete accounting: (a) avoided water consumption for power plant cooling, valued at approximately 0.3–0.5¢/kWh in the water-scarce Colorado River basin where Las Vegas draws its supply; (b) avoided land acquisition for power plant and transmission corridor siting, an increasingly significant cost as available desert land near load centers is consumed by data centers and other development; (c) grid resilience and avoided outage costs—distributed generation reduces the probability and severity of cascading grid failures during extreme heat events, when centralized generation is most stressed and outage costs are highest; (d) health co-benefits from avoided NOx, particulate, and ozone precursor emissions—estimated at 1–3¢/kWh for gas-fired generation in urban areas by EPA methodology; and (e) property tax revenue differential—rooftop PV on private homes generates property tax revenue for Clark County, while utility-scale generation on federal or utility-owned land may be partially or fully tax-exempt. When these omitted benefits are added to the avoided cost stack, the full social value of a rooftop PV kWh in Las Vegas during solar production hours is conservatively estimated at 18–25¢/kWh.

On the cost side, the homeowner's actual cost to generate that kWh is substantially higher than the solar industry's marketing implies. A representative 8 kW residential system in Las Vegas costs approximately $24,000–$27,000 before the 30% federal Investment Tax Credit, or $16,800–$18,900 after the credit. Most homeowners finance this cost. At a typical solar loan

rate of 5–7% over 20 years, the monthly payment is approximately $130–$155, or $1,560–$1,860 per year. An 8 kW system in Las Vegas produces approximately 13,000–14,000 kWh per year when new. The homeowner's financing cost per kWh is therefore approximately 11–14¢/kWh—before any maintenance, cleaning, or inverter replacement costs. Adding quarterly professional panel cleaning ($150–$300/year in the dusty desert environment), one inverter replacement over the system life ($1,500–$3,000 at year 12–15), and insurance premium increases, the homeowner's all-in cost rises to approximately 14–17¢/kWh averaged over the system's practical 15–20 year lifespan. This cost increases further as panels degrade: a system producing 75% of rated output by year 15 has an effective cost per generated kWh that is 33% higher than the new-panel calculation implies.

The economic reality confronting the Las Vegas homeowner is stark. The homeowner's all-in cost to produce a kWh is 14–17¢. NV Energy pays 10.5¢ for that kWh (Tier 4, 75% of retail). The homeowner loses 3.5–6.5¢ on every exported kWh. The only way the system "pays for itself" is through self-consumed kWh that displace retail purchases at 14¢—a net savings of zero to marginally positive after financing costs. The widely cited "6–8 year payback" is calculated by the solar industry using pre-financing system cost, rated (not degraded) output over 25 years, and the assumption that the homeowner consumes all generated electricity at full retail—none of which reflects reality for a financed system that exports 40–60% of its output to the grid at 75% of retail.

For rooftop PV to be a genuinely good investment for homeowners—one that reflects the full spectrum of benefits it provides to the utility, the grid, the community, and the environment—the compensation rate should be set at the full social avoided cost. The component-by-component buildup is: fuel and variable O&M avoided (4–6¢); capital recovery of the power plant that does not need to be built (3–5¢, rising toward 4–6¢ as construction costs escalate); transmission and distribution avoided (2–4¢); capacity and ancillary services (2–3¢); UHI mitigation and reduced community AC demand (1–2¢); avoided water consumption in the Colorado River basin (0.5¢); avoided CO_2 and criteria pollutant emissions (1–2¢); health co-benefits from cleaner air (1–2¢); and grid resilience value (1–2¢). The sum ranges from 15.5–26.5¢/kWh depending on the hour and season, with an annual average central estimate of approximately 21¢/kWh across all PV production hours. However, because Las Vegas PV output is heavily summer-weighted—roughly 60% of annual kWh are produced during May through September, when avoided costs are highest—the production-weighted average rises to approximately 23–24¢/kWh. During the summer peak hours (1–7 PM, June through September) when rooftop PV shaves the most expensive peaker generation, the full avoided cost reaches 25–30¢/kWh. This analysis therefore recommends a fair compensation rate of 25¢/kWh for Las Vegas homeowners. This rate is at the high end of the annual production-weighted average but at the low end of the summer peak value—the hours when rooftop PV provides its greatest grid and community benefits. It covers the homeowner's actual financing and maintenance costs (14–17¢) with sufficient margin (8–11¢) to make PV a genuinely attractive investment that drives adoption, and it still costs the utility and ratepayers less than building a new gas-fired power plant to meet the same demand. At current construction cost trajectories—with GridLab reporting combined-cycle costs approaching $2,500/kW and rising—the 25¢ figure may prove conservative within two to three years as the capital recovery component alone increases by 1–2¢/kWh.

The gap between what homeowners are paid (10.5¢) and what their power is worth (23–25¢) is not an accident. It is the predictable outcome of a regulatory process in which the utility that buys the power also controls the information presented to the commission that sets the rate. NV Energy argues that rooftop solar customers are "subsidized" by non-solar ratepayers—a claim that is accurate only if the full avoided cost stack, including capacity, T&D, environmental, health, and UHI co-benefits, is excluded from the calculation. When the full costs are counted,

the subsidy flows in the opposite direction: NV Energy receives approximately 23–25¢ of avoided costs for every exported kWh and pays the homeowner only 10.5¢, capturing a margin of approximately 55–58% of the value the homeowner creates. To put this in concrete terms: a homeowner with an 8 kW system who exports 6,000 kWh per year to the grid generates approximately $1,380–$1,500 in avoided costs for the utility system. NV Energy pays the homeowner $630. The utility and its shareholders retain $750–$870 per year, per solar customer. Across 105,000 solar customers, this transfer amounts to approximately $79–$91 million per year flowing from homeowners who invested their own money in generation infrastructure to a utility that invested nothing in producing those kWh. This is the opposite of a subsidy to solar customers. It is a subsidy from solar customers to Berkshire Hathaway's shareholders.

8.2. A Call for Transparent Valuation

This analysis calls for three specific reforms. First, the PUCN should require NV Energy to publish a transparent, time-differentiated avoided cost calculation that includes all six cost components identified in Section 5.5, updated annually with current gas prices, construction costs, and grid conditions. The current flat 75%-of-retail rate is a political compromise, not an economic calculation; it should be replaced with a rate that tracks actual avoided costs by time period. Second, the 100% sizing cap should be removed or raised to at least 150% of annual consumption, reflecting the reality that oversized systems provide additional grid capacity and UHI mitigation benefits that the current cap forecloses. Third, the PUCN should commission an independent value-of-solar study for the Las Vegas Valley—comparable to the studies conducted by Minnesota, New York, Maine, and other states—that accounts for the full spectrum of avoided costs including capacity, T&D, environmental, health, and UHI co-benefits. Until such a study is conducted, the default assumption should be that rooftop PV is worth at least its full avoided cost to the utility system, not a discounted fraction of the retail rate set through a process dominated by the utility that profits from the discount.

The convergence of the AI data center demand surge, tripling power plant construction costs, accelerating urban heat island effects, declining Colorado River water supplies, and the growing body of evidence linking nighttime temperatures to native species stress in the Mojave Desert creates an unprecedented alignment of economic, environmental, and ecological arguments for maximizing distributed rooftop generation. Planet warming is a global problem. The US is behind what Germany, Australia, Japan, and other nations are doing to deploy distributed solar. In a city with the highest solar resource in the continental United States, the policy that limits homeowners to 100% of their consumption and pays them 10.5¢ for power worth 25¢ is not merely suboptimal—it is indefensible. The numbers in this paper make that case. The policy response is long overdue.

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